Consolidated Edison Company of New York, INC.

Electric Rate Case

INDEX OF EXHIBITS

Volume 3

Exhibit__(EIOP-1)

T&D Capital and O&M Summary

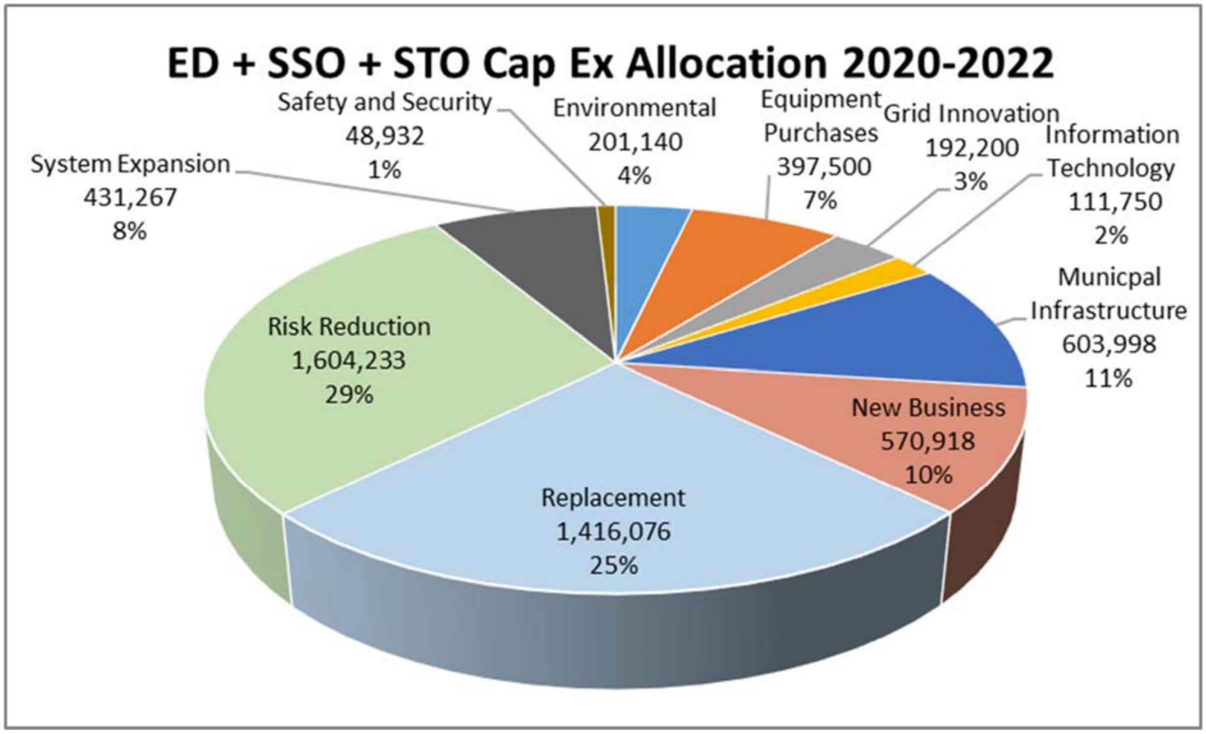
Schedule 1: T&D Capital Program and Project Summary

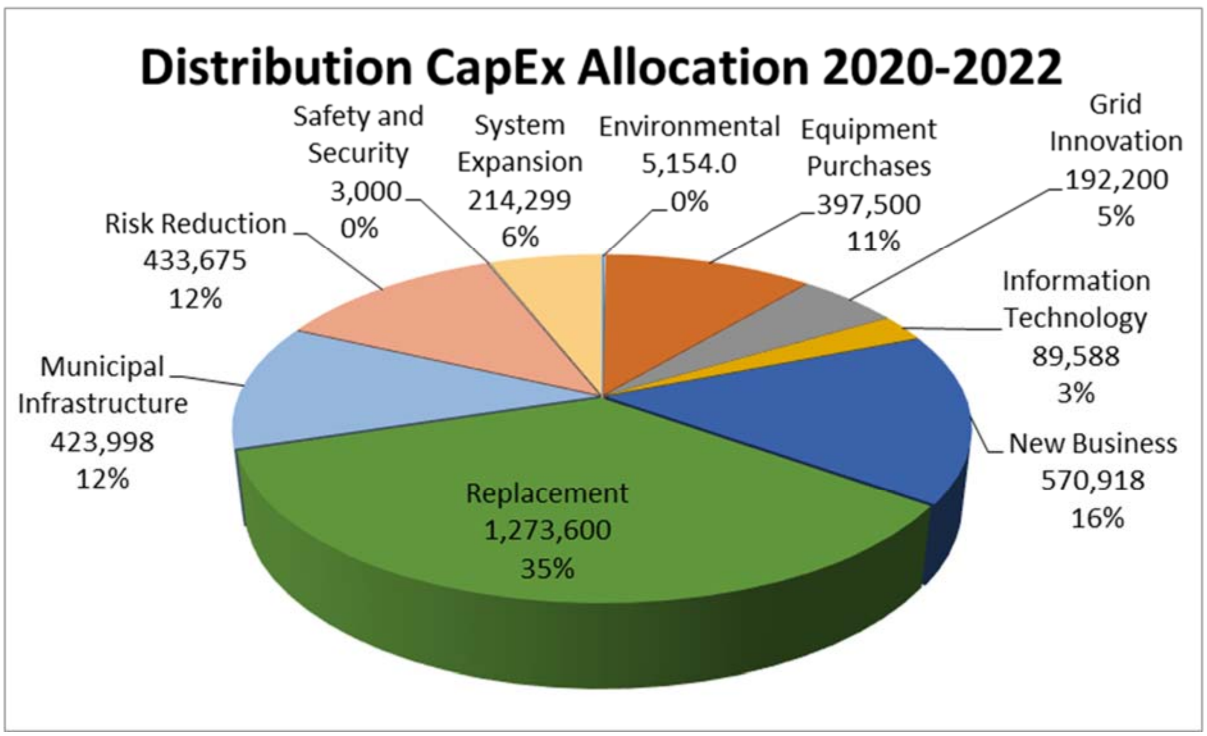
	Year Total			
	Current Budget			
	Total Dollars ($000)			
ELECTRIC	**RY1**	**RY2**	**RY3**	**3 Yr. Total**
Electric Transmission				
Environmental	25,586	25,600	25,600	**76,786**
Information Technology	8,802	1,400	1,750	**11,952**
Municipal Infrastructure	60,000	60,000	60,000	**180,000**
Replacement	10,976	11,000	11,000	**32,976**
Risk Reduction	35,680	173,916	274,550	**484,146**
Safety and Security	2,366	2,400	2,400	**7,166**
Sub-Total	**143,411**	**274,316**	**375,300**	**793,027**
Electric Substations				
Environmental	57,100	57,100	5,000	**119,200**
Information Technology	2,072	2,970	2,970	**8,012**
Replacement	36,500	36,500	36,500	**109,500**
Risk Reduction	197,303	253,264	235,844	**686,412**
Safety and Security	12,715	13,025	13,025	**38,766**
System Expansion	46,440	78,837	91,691	**216,968**
Sub-Total	**352,130**	**441,697**	**385,030**	**1,178,857**
SSO+S&TO total				
Environmental	82,686	82,700	30,600	195,986
Information Technology	10,874	4,370	4,720	19,964
Replacement	47,476	47,500	47,500	142,476
Risk Reduction	232,983	427,180	510,394	1,170,558
Safety and Security	15,081	15,425	15,425	45,932
System Expansion	46,440	78,837	91,691	216,968
Municipal Infrastructure	60,000	60000	60,000	180,000
Electric Distribution				
Environmental	718.0	3,718.0	718.0	**5,154.0**
Equipment Purchases	126,500	132,000	139,000	**397,500**
Grid Innovation	62,400	62,400	67,400	**192,200**
Information Technology	32,664	32,973	24,751	**90,388**
New Business	189,306	189,306	192,306	**570,918**
Replacement	426,900	431,750	414,950	**1,273,600**
Municipal Infrastructure	133,000	141,001	149,997	**423,998**
Risk Reduction	127,659	155,154	150,862	**433,675**
Safety and Security	1,000	1,000	1,000	**3,000**
System Expansion	80,937	71,652	61,710	**214,299**
Sub-Total	**1,181,084**	**1,220,954**	**1,202,694**	**3,604,732**
Electric T&D Total - Incl. Interference	**1,676,625**	**1,936,967**	**1,963,024**	**5,576,616**
TOTAL ELECTRIC				
Environmental	**83,404**	**86,418**	**31,318**	**201,140**
Equipment Purchases	**126,500**	**132,000**	**139,000**	**397,500**
Grid Innovation	**62,400**	**62,400**	**67,400**	**192,200**
Information Technology	**43,538**	**37,343**	**29,471**	**110,352**
Municpal Infrastructure	**193,000**	**201,001**	**209,997**	**603,998**
New Business	**189,306**	**189,306**	**192,306**	**570,918**
Replacement	**474,376**	**479,250**	**462,450**	**1,416,076**
Risk Reduction	**360,642**	**582,334**	**661,256**	**1,604,233**
System Expansion	**127,377**	**150,489**	**153,401**	**431,267**
Safety and Security	**16,081**	**16,425**	**16,425**	**48,932**
Total	**1,676,625**	**1,936,967**	**1,963,024**	**5,576,616**

Schedule 2: T&D O&M Program Change Summary

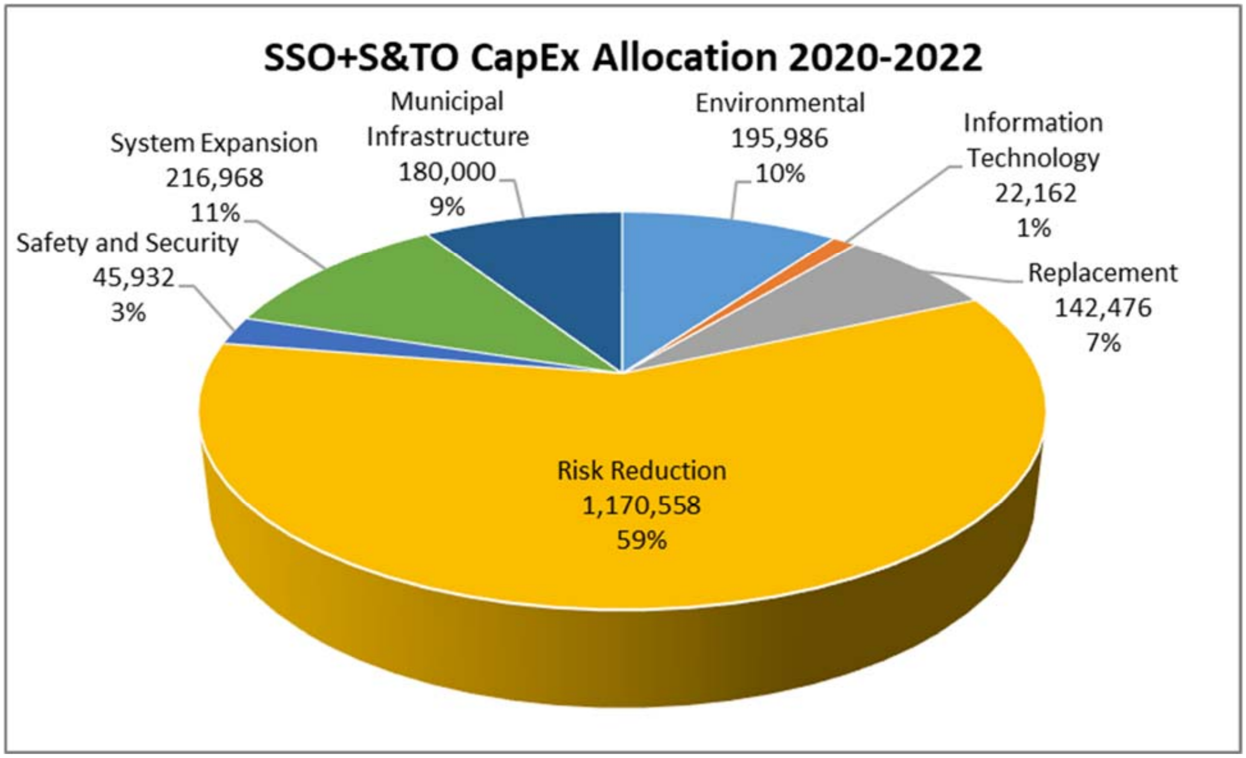
Infrastructure Investment Panel				
O&M Program Changes				
Summary				
($000)		**RY1 Program Change**	**RY2 Program Change**	**RY3 Program Change**
Electric Transmission	**Program Change**			
Safety and Security	Physical/Cyber Security	370	-	-
System Expansion	Specializied Transmission Planning Studies	100	-	-
System Expansion	138 and 345kv Shunt Reactor Priority Study	200	(200)	-
Information Technology	OSS Maintenance	237	-	-
	Sub-Total	**907**	**(200)**	**-**
Electric Substations	**Program Change**			
Environmental	Substation EH&S Risk Mitigation Program	11,945	(1,449)	(10,496)
Risk Reduction	Hellgate Dock Refurbishment (SSO Portion)	800	(85)	(715)
Risk Reduction	Roof Replacement Program	650	-	-
System Expansion	Cricket Valley Substation	400	-	-
	Sub-Total	**13,795**	**(1,534)**	**(11,211)**
Electric Distribution	**Program Change**			
Equipment Purchases	Meters & Other Customer Equipment	(333)	(860)	(1,087)
Risk Reduction	Emergency Response	5,646	(673)	(1,482)
Risk Reduction	Engineering & Other Services	4,600	200	480
Risk Reduction	Tree Trimming	2,000	-	-
Safety and Security	Structures/Poles	2,330	3,600	(5,400)
	Sub-Total	**14,243**	**2,267**	**(7,489)**
	TOTAL	**RY1 Program Change**	**RY2 Program Change**	**RY3 Program Change**
	Grand Total	**28,945**	**533**	**(18,700)**

Schedule 3: T&D Capital Allocation Categories





ED = Electric Distribution SSO = Electric Substations S&TO = Electric Transmission

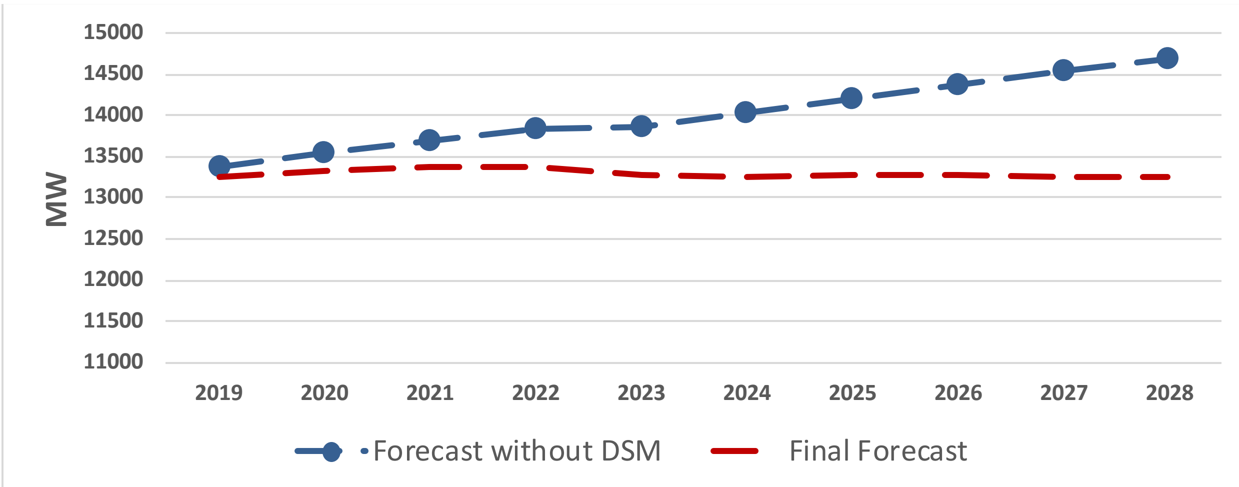


ED = Electric Distribution SSO = Electric Substations S&TO = Electric Transmission

Exhibit__(EIOP-2)

Electric Peak Demand Forecast

Schedule 1:
Long-Term Forecast – System Peak Demand
Ten-Year Electric System Peak Demand Forecast
(2019-2028)



Note: Forecast without DSM does NOT include Demand Response (excluding SCR), Con Edison EEPS (ETIP), NYSERDA EEPS/Clean Energy, NYPA EEPS, BQDM/Targeted NWS, and DMP; however, it does include other load modifiers. Final Forecast includes DSM and all other modifiers.

	2023		**2028**	
	Forecasted Peak (MW)	**5-Yr CAGR***	**Forecasted Peak (MW)**	**10-Yr CAGR***
Forecast Without DSM	13,873	1.0%	14,692	1.1%
Final Forecast	13,268	0.1%	13,247	0.0%

***CAGR = Compound Annual Growth Rate**

Schedule 2: 2019-2028 Network Area Forecasted Growth Rates

2019 – 2028 Network Area Forecasted Growth Rates		
Independent Summer Peak Demand Forecast (MW)		
Network Area (Excludes Radial Allocated Feeder Loads)		
Network	**5-Yr CAGR**	**10-Yr CAGR**
Pennsylvania	11.40%	6.40%
Borden	6.50%	5.10%
Fashion	3.90%	3.10%
Grasslands	3.50%	3.00%
Cortlandt	3.20%	2.50%
Turtle Bay	2.80%	2.30%
Borough Hall	2.90%	2.20%
Roosevelt	2.50%	1.90%
Williamsburg	2.40%	1.80%
Jackson Heights	1.90%	1.40%
Greenwich	1.80%	1.40%
Harlem	1.50%	1.30%
Sutton	1.60%	1.20%
Grand Central	1.50%	1.20%
Buchanan	2.40%	1.20%
Long Island City	1.30%	1.10%
City Hall	1.30%	1.10%
Ossining West	1.10%	1.10%
Kips Bay	1.20%	1.00%
Hudson	1.30%	0.90%
Cooper Square	1.20%	0.90%
Fulton	1.00%	0.80%
Ridgewood	1.30%	0.80%
Chelsea	0.90%	0.70%
Sheridan Square	1.00%	0.70%
Sunnyside	0.50%	0.70%
Granite Hill	0.70%	0.60%
Prospect Park	1.00%	0.60%
West Bronx	0.80%	0.60%
Southeast Bronx	1.00%	0.60%
Brighton Beach	0.90%	0.60%
Millwood West	-0.70%	0.50%
Randalls Island	0.60%	0.50%
Triboro	0.50%	0.50%
Fresh Kills	1.10%	0.50%
Freedom	-1.30%	0.40%
Greeley Square	0.50%	0.30%

2019 – 2028 Network Area Forecasted Growth Rates		
Independent Summer Peak Demand Forecast (MW)		
Network Area (Excludes Radial Allocated Feeder Loads)		
continued		
Network	**5-Yr CAGR**	**10-Yr CAGR**
Flushing	0.40%	0.30%
Cedar Street	0.00%	0.30%
Fox Hills	0.90%	0.30%
Canal	0.40%	0.30%
Plaza	0.50%	0.20%
White Plains	-0.10%	0.20%
Beekman	0.20%	0.10%
Lenox Hill	0.10%	0.10%
Park Place	0.30%	0.00%
Washington Street	0.00%	0.00%
Yorkville	0.20%	0.00%
Lincoln Square	0.10%	0.00%
Rockefeller Center	-0.40%	-0.10%
Madison Square	0.00%	-0.10%
Maspeth	0.00%	-0.10%
Bay Ridge	0.00%	-0.10%
Times Square	0.10%	-0.10%
Central Bronx	0.00%	-0.20%
Herald Square	-0.40%	-0.20%
Rockview	-0.30%	-0.30%
Harrison	-0.40%	-0.30%
Elmsford No. 2	-0.20%	-0.30%
Ocean Parkway	-0.10%	-0.40%
Woodrow	-0.60%	-0.40%
Jamaica	-0.20%	-0.40%
Central Park	-0.30%	-0.50%
Hunter	-0.40%	-0.50%
Richmond Hill	-0.30%	-0.50%
Park Slope	-0.40%	-0.50%
Bowling Green	-0.80%	-0.60%
Willowbrook	-0.60%	-0.70%
Flatbush	-0.60%	-0.70%
Washington Heights	-0.60%	-0.70%
Riverdale	-0.70%	-0.70%
Fordham	-0.50%	-0.80%
Pleasantville	-0.90%	-0.80%
Midtown West	-0.80%	-0.80%
Crown Heights	-0.70%	-0.90%

2019 – 2028 Network Area Forecasted Growth Rates		
Independent Summer Peak Demand Forecast (MW)		
Network Area (Excludes Radial Allocated Feeder Loads)		
continued		
Network	**5-Yr CAGR**	**10-Yr CAGR**
Sheepshead Bay	-0.90%	-0.90%
Rego Park	-0.80%	-1.00%
Wainwright	-1.10%	-1.10%
Battery Park City	-1.00%	-1.10%
Columbus Circle	-1.20%	-1.50%
Northeast Bronx	-1.30%	-1.50%
Empire	-2.50%	-1.60%
Mohansic	-4.60%	-4.50%

Exhibit__(EIOP-3)

T&D Grid Innovation

Schedule 1: T&D Grid Innovation Capital Program and Project Summary

Electric T&D		**Year Total**			
Grid Innovation		**Current Budget**			
		Total Dollars ($000)			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
SYSTEM EXPANSION					
Organization	**White Paper**				
Distribution	Advanced Employee Safety Tools	1,000	1,000	1,000	3,000
Distribution	Communications Infrastructure*	15,000	15,000	20,000	50,000
Distribution	Cybersecurity Test Environment	2,000	2,000	2,000	6,000
Distribution	Data Analytics Use Cases	2,000	2,000	2,000	6,000
Distribution	GIS	30,000	30,000	30,000	90,000
Distribution	Non-Network Resiliency with FLISR	2,100	2,100	2,100	6,300
Distribution	Smart Sensors	6,300	6,300	6,300	18,900
Distribution	Underground Network Resiliency	4,000	4,000	4,000	12,000
TOTAL ELECTRIC					
	Total Grid Innovation	**62,400**	**62,400**	**67,400**	**192,200**

**Communications Infrastructure O&M expense is covered under Risk Reduction O&M in Engineering and Other Services*

Schedule 2:

T&D Capital White Papers and Business Plan

Grid Innovation

	Capital
X	O&M

2020 – Distribution Engineering/Engineering and Planning

Project/Program Title	Advanced Employee Safety Tools
Project Manager	Joe Lenge, Stan Lewis
Hyperion Project Number	PR.23317512
Status of Project	Initiation
Estimated Start Date	January 1, 2020
Estimated End Date	December 31, 2023
Work Plan Category	Strategic

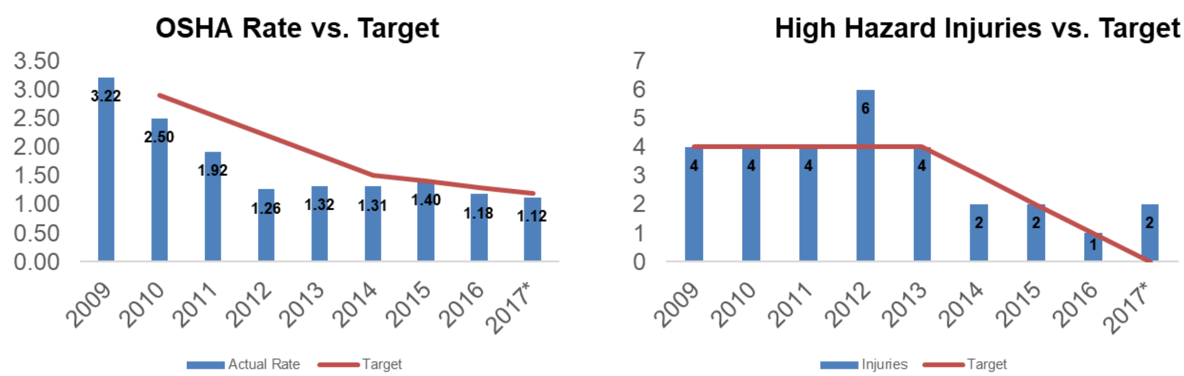
Work Description:
The same technology advances that are driving the proliferation of sensing and robotics technologies are also enabling the development tools to reduce the risk of the dangerous work Con Edison performs daily. The objective of this project is to deploy advanced employee safety tools to reduce safety incidence rates with a deliberate focus on reducing high-hazard injuries. Between 2020-2022, Con Edison will explore technology, such as primary voltage testing equipment with logging functionality and wireless connectivity, advanced splicing machine tools and other smart tools designed to reduce risks associated with high risk activities. These tools will be deployed on an annual basis, at an initial cost of $1 million per year, potentially increasing as field results are proven effective through field trials.

Primary voltage testing equipment with logging will be explored for use on equipment involved in the testing of electrical conductors or devices to confirm they are not energized. Real time status of equipment use will be available across the network to evaluate the progress of work... This device will generate a timestamp to compare against the testing logs to confirm testing is taking place during the appropriate steps in the process. This data will be subject to random checks and on demand by crew supervisors. Test dead logging devices cost approximately $2,000, and this program will deploy approximately 500 devices.

One underground splicing machine per year, at an approximate cost of $400,000, will be deployed and used to make 13 and 27 kV live-end caps ("LEC") on primary feeders. These feeders are installed in conduits to transport electricity from the supply substation to several network distribution transformers. Unlike overhead open-wire feeders, where larger clearances are available to allow safe live-line work, all underground cable feeders must be de-energized in order to perform work. Currently, processing and restoring feeders that open automatically consists of many steps, including positive identification, and placement and removal of additional protective grounds around the worksite required for workers. A LEC splice is a common splice that makes the immediate work area safe for work, while allowing as much of the feeder as possible to remain energized. A LEC is commonly used during adverse system conditions to expedite feeder restoration because it is quicker than a complete repair, thus resulting in an expedited means of electrical reinstatement. This project has been piloted through R&D and will be used more widely in the field on a borough-by-borough basis. The successful employment of the tools described in this whitepaper on a phased basis should inform an even wider employment beyond the rate case period in order to equip all operations and construction crews.

Other smart tools will be explored for use with employees performing critical work. These smart tools would be used by employees performing the tasks that have historically resulted in the greatest incidence rate of high-hazard injuries (e.g., lead mechanics). Data collected during the execution of this work will be subject to random checks and used to proactively correct any deviations from procedures. This will allow corrective actions preventing future hazards and will provide useful insights for developing enhanced training. Other smart tools are estimated to cost approximately $1,000 per unit and will be targeted for specific job functions at greatest risk for a high-hazard injury.

Justification Summary:
This program is being implemented as part of Con Edison's Grid Innovation plan. Through the Grid Innovation program, Con Edison will leverage new technologies to improve employee high-hazard safety, which is a strategic corporate priority for the Company. The Company's Grid Innovation goals include a focus on improving safety, both for the public and for employees. To do so, the Company will leverage technology for tools and analytics to improve its operations. For employee safety, the Company has made strong progress in recent years in reducing both the overall OSHA incidence rate and the high-hazard injuries; however, the incidence rate is not a direct indicator of severe injury potential and avoidable high-hazard injuries persist (see figure below).



Given the nature of delivering high energy, the risk for high-hazard injuries is not completely avoidable; however, the Company believes it can be lowered further through technology and safety tools that address precursors to high-hazard workplace injuries, increase awareness during high-hazard tasks, or use robotics for dangerous tasks.

<u>Primary Voltage Testing Equipment</u>
there are many precursors to workplace injury and fatality, including productivity safety stressors, vulnerability to high energy, and outside safety influences. Advanced safety tools, such as test dead logging devices, allow severe injury and fatality precursors to be identified and eliminated. Device data can be used to take corrective action and improve safety training procedures.

A common precursor is an inability to recognize high energy. Crews working in environments where there is possible exposure should perform dead testing. Timestamping test dead equipment use increases the likelihood high energy is identified. Other smart tools will also ensure workers performing tasks involving high energy are following procedures. Single individuals have fewer human performance tools available; multiple employees should be involved to prevent errors. Other smart tools would ensure employees are engaged while performing work tasks and there are no visible distraction sources.

<u>Underground Splicing Machines</u>
the splicing machines deployed through this program will reduce the risk to Company employees during the high-hazard task of making primary cable safe for splicing. Furthermore, the splicing

machine could potentially streamline feeder processing during outages by enabling field crews to quickly and safely restore service through live end capping. The successful pilot of both this machine and a new cold shrink pre-mold LEC has been tested in R&D and requires less preparatory work and installation time to implement a feeder repair.

Other Smart Tools

To maintain and improve its safety rate, the Company must utilize available safety tools to control and eliminate present and future hazards. Smart tools that collect additional data on the nature of Con Edison's field operations would improve work quality and enhance tracking capabilities. Based on the success of vehicle cameras in reducing the motor vehicle incidents, reviewing smart tool data both at random and defined intervals can provide leading data on employee behavior, facilitate individual and organization-wide risk reduction through coaching, and reduce at-risk behavior occurring among participating organizations.

Supplemental Information:

- Alternatives: Other options considered by the cross-functional task force that was investigating high-hazard injuries include modifying disciplinary processes, performing random spot checks, and recertification of lead mechanics. Ultimately, these options were not selected because they introduce significant administrative overhead or are not as effective for improving employee safety.

- Risk of No Action: Currently, the Company holds an OSHA rate of 1.12. To achieve this, the company focuses on building strong relationships with the union on safety, formalizing job planning with emphasis on high-energy tasks, and strengthening barriers against high-energy events. High hazard events still occur, and thus, significant risk of high-hazard injury remains. Without action through this program, the Company could plateau and not achieve further reduction in significant high-hazard injuries.

- Non-financial Benefits: The deployment of advanced employee safety tools offers the following non-financial benefits:
  - Reduced incidence rate and number of high-hazard injuries and associated lost time for injured employees
  - Increased protection against injury and fatality precursors

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis:

  In 2018, Con Edison management established a cross-functional task force to evaluate high-hazard injuries, their causes, and potential means of lowering the high-hazard injury rate. The recommendations from that team's efforts informed this program. R&D is currently exploring the development of a prototype for the primary voltage testing equipment, and the results of that will also inform this program.

- Project Relationships (if applicable):

- Basis for Estimate:
  Costs for this effort were determined by using current equipment costs and costs associated with the current R&D efforts.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	18	24	17	198
M&S	-	761	760	760	6,080
A/P	-	-	-	-	-
Other	-	68	67	67	540
Overheads	-	154	149	156	1,182
Total	**-**	**1,000**	**1,000**	**1,000**	**8,000**

X	Capital
X	O&M

2020 – Shared Services / Information Technology

Project/Program Title	Communications Infrastructure
Project Manager	Wendell Little
Hyperion Project Number	PR.23317516
Status of Project	Engineering /Planning
Estimated Start Date	January 1, 2020
Estimated Completion Date	December 31, 2023
Work Plan Category	Operationally Required

Work Description:
As Con Edison deploys Grid Innovation systems, applications and devices, many will require supporting communications infrastructure to maximize the value of the investment. The Company will develop communications infrastructure to manage the transport of the data generated by these systems. The Company's communications strategy must deliver sufficient capacity and diversity of communications channels to accommodate the necessary systems and devices with the required levels of service. This infrastructure generally must be installed or upgraded in advance of planned device deployment. Further, this strategy must address cybersecurity and other operational requirements.

To accommodate future systems, applications, and devices, the Company will expand or enhance existing communications infrastructure to meet the needs of each application. This infrastructure expansion will span a twenty-year horizon in alignment with Con Edison's Grid Innovation plan. Optimal communications solutions were identified through system, application, and device requirements gathering and may include:

- Expanding the Corporate Communications Transmission Network ("CCTN"), e.g., new fiber
- Expanding Itron Advanced Metering Infrastructure network ("AMI network") on a limited basis if necessary based on communications traffic analysis
- Expanding commercial carrier wireless or wireline communications

Expanding CCTN:
Con Edison owns and operates a private communications network called the CCTN. This network enables secure communications circuits for SCADANet, voice, video, feeder protection, and the computing and storage environment. CCTN enables computing resource consolidation, disaster recovery, as well as the reduction of public carrier costs. There are over 200 Company locations which host the fiber optic and ancillary equipment used by CCTN. The CCTN equipment is installed in communications rooms, communications huts, and enclosures at the various facilities. These facilities are typically at Con Edison owned properties, including substations and owned or leased utility poles and transmission towers. Since the late 1980s, over 600 miles of fiber optic cable has been installed to provide CCTN communications services. In most cases, these fiber runs were combined with electric distribution cable installations. The need to expand capacity to address Grid Innovation

requirements drives this expansion project. Enhancement options include adding AMI access points to existing CCTN facilities, extending CCTN reach or services over microwave, and building new CCTN facilities, depending on local topography and SCADA or capacity needs.

During the years of 2020 through 2022, Con Edison will build fiber routes in each borough, extending the reach of the CCTN facilities. The location of the CCTN facilities build out is dependent on the locations of the planned installation of SCADA assets.

Recently, the Company has explored innovation to include fiber optic cable and/or microducts alongside primary distribution cable to enhance communications on our distribution network. Fiber imbedded in the cable or blown through the included microducts will provide a communications pathway for data gathering. Available fiber optic cable will enable data transfer from numerous underground cable structures to a common communication point. Use of this technology for Grid Innovation infrastructure will be done on a limited basis to selectively extend the reach of communications networks. As this technology is proven effective through field trials, it may be used on a more widespread basis.

Expanding AMI network and/or modifying for SCADA readiness:
Capacity planning will need to be performed prior to the introduction of any new device on the AMI network to provide reliable service and communications. Based on this analysis network reinforcement work may be required, consisting of adding access points in areas where additional equipment is required.

During the years of 2020 through 2023, the Company will expand the AMI network to improve performance, at a rate of approximately thirty additional access points per year. The traffic model analysis uses empirical data and expected deployment of additional equipment to project utilization per access point. Using that information, the Company can optimize utilization while maintaining acceptable performance for all applications based on design parameters. This process will highlight where additional access points are needed to maintain acceptable performance in localized areas.

The radio frequency ("RF") mesh is not static and will be regularly expanding to accommodate new business, new applications and will be affected by the RF profile impacts of new construction and other efforts. The Company envisions a reliability effort similar to its summer load relief, the details of which will be determined as our network expands and conditions change.

Expanding commercial carrier wireless or wireline communications:
Carrier services present another communication channel for Con Edison assets for both wireless and wireline uses. A wireless option that has proven effective in the Company's dense urban environment, and can be made suitably secure and responsive for SCADA control devices, is to use wireless modems and networks through carriers like Verizon or AT&T. Wireline solutions the Company is evaluating include Multiprotocol Label Switching ("MPLS") services over fiber optic cable. The deployment of high-speed wireline services over fiber presents another option for backhauling AMI access points. This offers more takeout points, a lower hop count, and higher performance for SCADA applications.

These options are suitable when performance requirements for certain applications exceed the design capability of the AMI network. Though effective, the downside to this approach is that it is relatively expensive to scale as each modem requires a carrier account, and it does not provide the network control or resiliency that is needed during extreme events.

During the years of 2020 through 2023, the Company expects it will deploy additional wireless modems and wireline communications where appropriate.

In practice, the communication path to bring field asset data back to upstream management systems will leverage a combination of these options. For instance, the Company could leverage the AMI network to transmit data from field assets and other edge devices to AMI access points. The backhaul network would then transmit the data through the established CCTN and/or carrier networks to decision management systems and other applications.

O&M

Any significant expansion of communications infrastructure sustained over several successive years as is required to support the expected expansion in the number and complexity of applications that define Grid Innovation will inevitably result in an increase in O&M activity. The O&M increases will occur in three areas, namely, cost for new carrier services, cost for new staff, and cost for more maintenance activity.

<u>Justification Summary</u>:

Communications infrastructure is foundational to Grid Innovation. Deploying additional communicating devices without the requisite performance, (e.g. bandwidth, latency, etc.) and supporting infrastructure would lead to stranded costs of the assets or even disruption of existing assets that use the communication networks. This infrastructure is a requirement of Grid Innovation and Distributed System Platform ("DSP") projects, including Volt-Var Optimization ("VVO"), Overhead and Underground Resiliency, and Distributed Energy Resource Management System ("DERMS"). Each of these investments relies on field assets, like smart sensors and controllable network protectors, to inform Company applications and systems for planning and/or operational purposes. These Grid Innovation systems, applications, and devices will provide real-time visibility and control of grid assets and distributed energy resources ("DER") on the system.

The holistic design of the communications infrastructure for Grid Innovation addresses several departmental and corporate risks, including:

- Failure of Distribution Automation and Smart Grid applications
- Failure of critical business applications
- Infrastructure constraints
- Safety
- Failure of public carrier wireless services

Each of the proposed communication solutions has distinct benefits and applications, described below.

Expanding CCTN:
CCTN continues to provide the Company with a high-speed, reliable, and cost-effective communication alternative to public carriers. Through experience, CCTN regularly outperforms the carriers on reliability, bandwidth, priority, and restoration. Typically, CCTN is designed to be more disaster resilient, with greater backup power or onsite generation.

As such, CCTN provides diversity and redundancy to public carrier circuits for critical applications that may require it. The communications diversity provided by CCTN enables the Company to maintain operations independent of the public carriers, which is critical for 'black-sky days', such as major storms or other unforeseen events that substantially impact communications systems including public carrier services. Communication requirements for data, voice, feeder protection, SCADA and video circuits will result in the installation and deployment of modern communication technologies to many Company facilities. CCTN provides the network for SCADA protection and data services to critical substations, necessitating capital to expand the presence of the network to meet expanding SCADA and automation needs. It serves as the corporate backbone for communication services for the foreseeable future.

The additional communication pathway created through the development of fiber-embedded primary cable is an important development in a dense urban environment because wireless communications to and from field devices can be challenging. Field device information will be communicated through the fiber to strategically located wireless communication devices for further backhaul. This may also offer cost savings by reducing the number of wireless communication devices necessary to monitor the system.

Expanding AMI network and/or modifying for SCADA readiness:
Leveraging the AMI network in most cases will be the lowest cost option for backhaul sensing and data from non-control equipment, which often reports small payloads infrequently by exception. The use of AMI for SCADA devices is being pursued. Additional communications devices may be needed to preserve network performance in a SCADA-rich environment and extend the reach of the AMI network to the sensing devices deployed as part of Grid Innovation.

Devices that may use the AMI network include network protector relays, smart sensors, capacitor bank monitors; power quality, overhead reclosers; demand response assets, and other future edge devices that could utilize the AMI network.

Expanding commercial carrier wireless or wireline communications:
The commercial carrier wireless or wireline communications offer SCADA-ready latency and can be designed to meet cybersecurity requirements for SCADA applications. Wireless commercial services are typically more scalable for deployment when devices require a short lead time. Though wireline services require more lead time, there are certain locations where extending commercial carrier wireline solutions is a more cost-effective solution than extending CCTN. Where commercial carrier wireline solutions are extended, and ultimately connect to CCTN, it extends the CCTN point of presence. The use of wireline commercial

carriers to extend CCTN point of presence becomes more important as an AMI mesh network expands the number of sites that are viable for commercial carrier extension, greatly expanding the usefulness of network.

Upgrades to commercial carrier wireline services are also critical for area and unit substations without existing CCTN facilities to increase the capacity in order to handle the increased demand of SCADA-enabled grid assets. Commercial carrier and broadband services provide redundancy and additional diversity among carriers in the event of network outages of company-owned networks like CCTN (and vice versa). Furthermore, these may be the only options available where the Company's networks do not provide coverage or network build out is not cost-effective.

Devices that may use commercial wireless or wireline communications include targeted network protector relays and smart sensors; distribution automation reclosers and switches on overhead circuits; underground interrupters; capacitor bank monitors; and some power quality meters to enable VVO.

O&M
Usage charges will apply for incremental wireless and wireline services needed to backhaul additional access points in the private meshed wireless access network that provides last mile connectivity to the various endpoint assets described above and for assets that communicate directly over carrier wireless networks.

The expansion of fiber optic outside plan and telecommunications facilities housing multi-point and point to point microwave terminal and MPLS and DWDM network gear will require additional technical staff to design, deploy, configure, troubleshoot, maintain, and upgrade this plant over the lifecycle of these complex systems. There will be increases in common plant like rectifiers, uninterruptible power supply units, and batteries that will also need to be maintained.

Any increase in outside plant incurs exposure to risk to damage from normal field activity and weather events. There will also be repairs associated with normal failure for equipment that is in service. Some examples of these maintenance activities include replacement and repair of fiber optic cables damaged by construction interference, electric system burnouts, rodents and crews working in manholes with fiber cable; storm damage to overhead fiber optic cables; ongoing proactive inspections and remediation including tree trimming; replacement of electronic components like optical cards, power supply units, transmitters, lightning and grounding protection and radio frequency antennas and waveguides.

Supplemental Information:

- Alternatives: For each field device, multiple communication channels were considered. The communication channel was ultimately selected based on the following:

- Risk of loss of communication – where the redundancy and communication channel requirements are more stringent as the risk increases when that communication channel is lost
- Company vs. third party ownership – where company ownership provides greater control, particularly during extreme events
- Backup power requirements – where locations with available backup power generation or batteries can meet more stringent backup requirements
- Cybersecurity requirements – where cybersecurity requirements vary for monitoring devices vs. those that will be controlled by operators

- Risk of No Action: Risks of no action include limited communication with field assets and edge devices, limiting data acquisition and control of applications, and eroding the value of the investments. Failure to consider holistic solutions to communications needs could result in unreliable communications for critical grid control assets or the inefficient buildout of network capacity. Interruptions to control devices reduce an operator's visibility and control, which limits their responsiveness to manage a dynamic grid and presents a risk to maintaining system reliability. Inefficient capacity on these networks would result in bespoke communications solutions deployed on a device basis, rather than leveraging the scale of the networks to appropriately build capacity. In addition, without a comprehensive communication strategy and funding to preserve it, the Company will not be in a position to support Reforming the Energy Vision ("REV"), DER integration, and other customer focused initiatives.

- Non-financial Benefits: In addition to enabling many of the Grid Innovation and DSP investments that deploy communicating devices, like structure observation systems and controllable network protectors, the proposed communication enhancements maintain cybersecurity and provide resiliency through diverse communications.

- Summary of Financial Benefits (if applicable) and Costs: While this project does not offer immediate financial benefits, as additional company-owned infrastructure is built to support the additional communicating devices, the Company will have a clearer path to retiring some legacy communications like leased Distribution Automation System ("DAS") radio sites. The annual O&M cost for DAS sites is about $850,000; i.e. nominally $40K/month for vendor support and $340K/year in site lease costs.

- Technical Evaluation/Analysis: Information Technology ("IT") performs planning and analysis on all technologies introduced. Solutions are investigated in conjunction with the IT strategy and vision planning process. Interaction with IT advisors, carriers, vendors and Company employees ensure the selection of the optimal solutions. Traffic model analysis~~,~~ measures the current performance of the AMI network and projects performance for areas where deployment is not yet complete. This analysis measures both the average utilization of the network and the 95th percentile performance to give a measure of both the overall capacity and the peak-traffic performance.

  The Company conducted workshops to determine the communication requirements of each field device to be deployed through Grid Innovation. Workshop participants included subject matter experts on CCTN, AMI, SCADA, and field assets. Requirements such as bandwidth, latency, and control were documented in a communications matrix.

- Project Relationships (if applicable): The Grid Innovation and DSP projects requiring communications infrastructure include:
  - VVO
  - Overhead Resiliency
  - Underground Resiliency
  - DERMS
  - Smart Sensors
  - Network Protector Relay Upgrades

- Basis for Estimate: The estimates are based on the nominal costs of trenching for new cable (where necessary), facilities, equipment (e.g., fiber cable, routers, and modems), labor and overheads, and building additional equipment and facilities for the different types of communications infrastructure. Nominal cost estimates are based on historical spending for each type of communication. In practice, the costs will vary depending on the specific deployment of the expected endpoints (e.g., incremental footage, facilities).

Annual Funding Levels ($000):

Capital

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	680	671	917	713
M&S	-	-	-	-	-
A/P	-	11,021	11,113	14,667	11,865
Other	-	979	987	1,302	1,054
Overheads	-	2,322	2,231	3,121	2,370
Total	**-**	**15,001**	**15,002**	**20,000**	**16,001**

O&M

Engineering and Other Services

Incremental Change due to this project to the Engineering and Other Service program
Future Elements of Expense

EOE	Request 2020	Request 2021	Request 2022
Labor	-	-	-
M&S	-	-	-
A/P	600	200	500
Other	-	-	-
Overheads	-	-	-
Total	**600**	**200**	**500**

Historical Elements of Expense total Engineering and Other Services program

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Actual 2018
Labor	6,139	6,328	6,468	6,347	5,851	5,417
M&S	191	213	147	76	36	32
A/P	987	1,525	603	1,929	882	319
Other	17,427	18,779	18,918	20,469	21,512	21,911
Total	**24,744**	**26,845**	**26,136**	**28,821**	**28,281**	**27,679**

Future Elements of Expense total Engineering and Other Services program

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	5,531	6,811	6,811	6,811	6,811
M&S	33	33	33	33	33
A/P	326	3,646	3,846	4,326	4,326
Other	22,372	22,372	22,372	22,372	22,372
Total	**28,261**	**32,861**	**33,061**	**33,541**	**33,541**

X	Capital
	O&M

2020 – Information Technology / Information Security

Project/Program Title	Cybersecurity Test Environment
Project Manager	Richard Schnauthiel
Hyperion Project Number	PR.23317522
Status of Project	Planning
Estimated Start Date	2/1/2020
Estimated Completion Date	12/31/2023
Work Plan Category	Operationally Required

Work Description:
Con Edison will establish an advanced testing environment for information security solutions to maintain a strong, proactive security posture as additional communicating devices are used to increase grid visibility and awareness. This will facilitate comprehensive, quick, and accurate vulnerability discovery and remediation. This test environment will be used to confirm or validate third party vendors and partners with whom the Company shares business, customer, or other sensitive information.

Today, periodic penetration testing and scanning is often limited to individual systems or solutions. Vendor vulnerabilities are currently remediated through a question-answer process, which are often difficult to validate. Based on the more rapid proliferation of communication devices, both Company-owned and those owned by third parties, current practices must be adapted to quickly, thoroughly, and holistically assess new devices at the expected rate of deployment.

The project includes capital investments in testing tools, the lab environment and training to enable the analysis of Information Technology (“IT”) equipment, Operational Technology (“OT”) equipment, workbenches, tools, facilities equipment, etc. This lab environment will include the replication of production networks, to the extent possible, including current security tools, networking equipment, and other devices/tools. It will provide testing capabilities for new and existing solutions.

Justification Summary:
This program is being implemented as part of Con Edison’s Grid Innovation plan. As Con Edison deploys additional communicating equipment for sensing and control, it must maintain its high standards for cybersecurity. The rapid penetration of additional field sensors and communication points introduces additional vulnerabilities and cybersecurity risks to Con Edison’s electric system, with an expectation of continued growth in the rate of complexity, size, external coupling, etc. While deployment of sensors and grid edge technologies creates opportunity for the company, it also carries inherent risks. As part of the Grid Innovation effort, the Company strives to thoroughly, quickly, and frequently test, discover, and remediate vulnerabilities to minimize information security risk.

A dedicated test environment for the Grid Innovation related technology, with dedicated tools and a sophisticated testbed, will allow the Company to quickly and thoroughly assess these items and seamlessly validate cybersecurity risk mitigation/remediation.

Supplemental Information:

- Alternatives: The alternative to a Company-operated test environment is to rely on third-party cybersecurity testing solutions. The risk with this approach is third parties may not perform their cybersecurity testing to the Company's standards. Furthermore, third party testing is limited in scope to the interactions and dependencies with individual production tools, which does not reveal a complete, holistic view of the production environment. Additionally, a test lab would likely allow quicker setup and execution of common use cases, leading to more efficient identification of risks, problematic interactions/dependencies, and requirements which may not be apparent without a replication of the production environment. Without such an environment, testing would require more overhead time/effort to stand up, generate necessary traffic/communications, and mimic production needs and findings.

- Risk of No Action: As new systems, vendor solutions, and communication devices proliferate, not establishing a dedicated cybersecurity testing environment may increase cybersecurity/operational risk. These additional devices may be tightly coupled with critical production systems, which magnifies the potential attack vectors and stresses the current testing systems and processes.

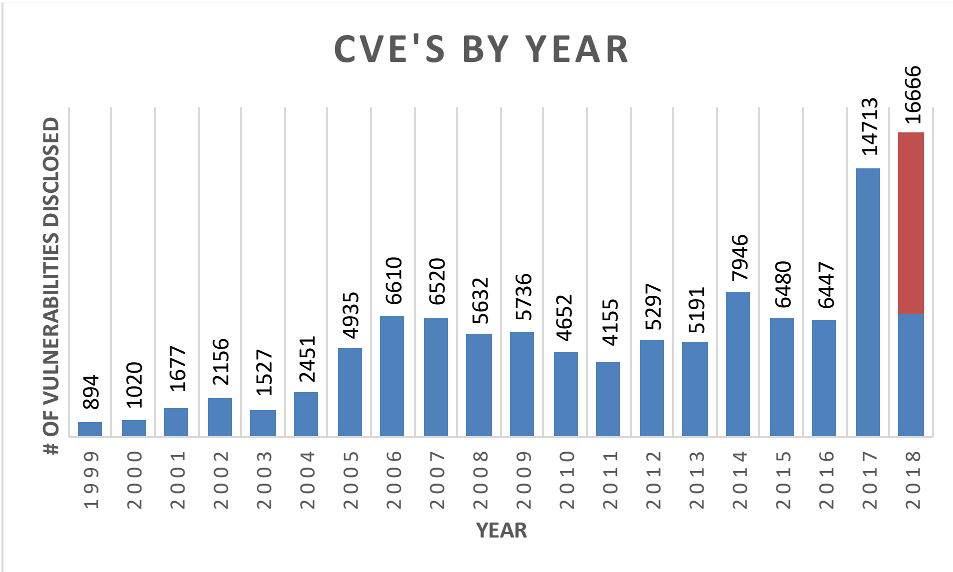
- Non-financial Benefits: The non-financial benefits of this test environment include increasing customer and employee information protection(s), reducing the possibility of intrusion into Company systems, using resources more efficiently to perform cybersecurity assessments, and reducing the gaps in the current question-answer process.

- Summary of Financial Benefits (if applicable) and Costs: The financial benefits from this investment are difficult to quantify, but are related to quicker detection of product vulnerabilities, a lower risk of compromise, and a reduced chance of operational impact, data loss, and activating cyber insurance. Also, by making a test environment with reusable advanced tools, the process can be made more repeatable, thus reducing costs.

- Technical Evaluation/Analysis: The Department of Homeland Security, National Cyber Security Division funds the maintenance of the well-known and respected Common Vulnerabilities and Exposures ("CVE") system which lists publicly known information-security vulnerabilities across devices, industries, etc. The following is the number of CVE's listed in the last few years:

Year	2015	2016	2017	2018 Estimate
Number of CVE's	6,480	6,447	14,713	16,666 (6,782 YTD through May)

A graph of the vulnerabilities since 1999 shows an average increase, with a sudden spike in 2017. The number of CVEs YTD through May 2018 has nearly approached the pre-2017 peak.



- Project Relationships (if applicable): Most of the Grid Innovation system and equipment deployments leverage communicating devices, such as the Distributed Energy Resources Management System ("DERMS"), network protector relay upgrades, and automated switches to support overhead fault location, isolation, and service restoration ("FLISR").

- Basis for Estimate: High level estimates include hardware, software, initial licensing, networking equipment, and necessary integrations to other systems. Where possible, estimates were benchmarked against comparable projects.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	68	80	66	163
M&S	-	-	-	-	-
A/P	-	1,490	1,490	1,490	2,980
Other	-	132	132	132	$265
Overheads	-	309	297	312	592
Total	**-**	**2,000**	**2,001**	**2,000**	**4,000**

X	Capital
	O&M

2020 –Information Technology/Business Intelligence and Middleware

Project/Program Title	Data Analytics Use Cases
Project Manager	Peter Maselli
Hyperion Project Number	PR.23317468
Status of Project	Engineering/Planning
Estimated Start Date	January 1, 2020
Estimated Completion Date	December 31, 2024
Work Plan Category	Strategic

Work Description:
The objective of this program is to develop and deploy a series of Grid Innovation data analytics use cases, leveraging the Enterprise Data Analytics Platform ("EDAP"), to fully utilize the existing and emergent stores of utility and customer data. EDAP is a big data platform designed for utilities, first implemented for Advanced Meter Infrastructure ("AMI") related use cases. The EDAP design uses conceptual models of all the attributes and processes related to specific data entities or domains, which enables data to be leveraged across multiple use cases. EDAP is at the core of the Company's expanding Analytics Center of Excellence ("COE"), which will oversee the prioritization and data governance standards needed for successful implementation of Grid Innovation use cases.

For any use case, there are common elements of work necessary to generate business value. These include:

- Integrating data sources – Determining the system(s) of record and identifying the periodicity with which the data is updated. Many of the initial use cases leverage common sources of data, such as:
  - Work Management System ("WMS") – for asset information, data regarding the status of work in progress, and inspection cycle history
  - Network Remote Monitoring System ("Net RMS") – for streaming data from the network transformers (e.g., voltage, pressure)
  - Meter Data Management System ("MDMS") – for customer and usage data to correlate customer usage to equipment health
- Modeling the data – Transforming the data as needed for consistency and modeling the data into the type model of the platform
- Performing the analysis – Developing or licensing the applications needed to extract valuable insights from the data. This may include using the native machine learning algorithms of the platform or business rules developed by Distribution Engineering

For each use case, the Company will procure the additional storage or compute capacity necessary to store the additional data that is integrated and run the algorithms to perform the analysis.

Initial candidate use cases for this program (see below) are largely oriented toward asset health applications; however, as the program and its capabilities mature the businesses will develop use cases to address different challenges or evolve capabilities within existing use cases.

<u>Asset Health</u>
Currently, Con Edison maintains equipment and inspects structures on a programmatic time-basis. Asset data is used to react to problems, rather than analyzed for condition-based or predictive

maintenance. For the approximately 27,000 network transformers, the Company has developed proof of concept internal applications Remote Monitoring System ("RMS") Analyzer for Network Equipment ("RANE") and Smart User-Interface for Network Equipment ("SUNE"). These applications provide greater visibility to the equipment health and augment the engineering analysis to identify defective NWPs, transformers in jeopardy of failure, and other equipment defects with low priority remote inspections. However, these are limited in scope to a single type of equipment, require point to point system connections, and are limited by the capabilities of the visual basic programming and hardware currently used. Furthermore, based on the underlying technology, these applications can only be business-rule based and cannot leverage the latest machine learning technology.

The Company will develop or license an Asset Health analytics application similar to RANE and SUNE on EDAP for equipment (e.g., network transformers, non-network switches, unit-substation assets). Data will be integrated from systems, such as Poly-Voltage Loadflow ("PVL"), WMS, NetRMS, Feeder Outages, power quality and load flow applications, to the enterprise platform for Asset Health analytics usage. The tool will then utilize the sensor data, environmental data, loading, and historical failure data to assess equipment and sensor health, failure probability and to identify impact severity in the event of equipment failure, such as critical customers, high energy location, and large outages.

For structure monitoring, the Company is deploying the Smart Observation System to monitor and respond to combustible gasses, stray voltage, thermal anomalies, and visual deficiencies. This data is currently collected and transmitted back to a secure cloud storage solution. As the sensors are deployed in the Company's 250,000 structures, Con Edison will use a data analytics application to identify anomalies and respond to emergent conditions. Similar types of analysis (trend recognition, anomaly detection, predictive failures) would be applied to structures and equipment, and the Company will evaluate whether a single application license could be used for both structures and equipment.

Work Prioritization

Con Edison engineers have developed an application that prioritizes system deficiencies (such as open mains or overloads) for the underground secondary network. This application uses a weighted variable decision matrix and presents a priority score on a graphical overlay. Currently, the decision matrix is determined based on engineering knowledge and principles; however, the Company will apply the machine learning capabilities of the platform to gauge the effectiveness of those rules and determine the correlation of the system deficiencies to the metrics most impactful to customers (outages and power quality disruptions). The existing application leverages data from the load flow model, critical customer inventory (Emergency Operations System ("EMOPSYS")), asset data (WMS), and customer data (Customer Information System ("CIS")/Cufflink). Additional data sources (e.g., street salting, paving/protected street, and weather data) will be integrated to the EDAP to further refine optimize the prioritization of work.

The Company will use a prioritization framework to evaluate use cases and determine how to apply the program budget. The prioritization framework accounts for key attributes of the use case, such as the ability to leverage data already integrated, the maturity of the use case in the industry, and the suitability for the enterprise platform, among others. The Data Analytics COE and Data Analytics Steering Committee make the prioritization decisions. Once a use case is fully developed and prioritized, the Company estimates the data can be modeled and an application developed within one year. The Company anticipates that it will develop the platform capability and integrate data sets in phases, implementing capabilities as the data sources (e.g., sensors and communicating control equipment) proliferate.

Justification Summary:
Advanced data analytics is an essential tool to provide the systems intelligence to make use of the additional sensors and communications technology delivered through other Grid Innovation and Distributed System Platform ("DSP") investments. Machine learning and artificial intelligence offer the ability to sift through and process the increasing volume of data being produced at the grid edge. These advanced capabilities are existing functionalities of the EDAP that Con Edison has already implemented as part of the AMI rollout. EDAP, as a scalable cloud-based big data platform, is well suited to scale and add data as required for various use cases.
As additional data sources are modeled and integrated on the EDAP platform, the Company realizes economies of scale and network effects, through reduced incremental costs for each future use case that can leverage the same data sources. Network effects refers to the benefit where additional sources of data integrated for one use case makes the platform more valuable to other applications that can leverage that data. For instance, many of the use cases defined here leverage customer or usage data that is already modeled on EDAP at no additional cost. The same will be true of future use cases that leverage the WMS or Net RMS data that will be modeled as part of these use cases.

Each of the initial use cases described above also provides specific benefits.

Asset Health
Current practices for both equipment maintenance and structure inspections rely on time-based programmatic inspection and replacement of equipment. Through additional sensing and advanced analytics, the Company can begin to transition to condition-based equipment maintenance and inspections. This change in approach will lead to fewer catastrophic equipment failures, reducing the public safety risk and Alive on Backfeed events and expense of replacing equipment while it is still serviceable. The benefits of using the enterprise data analytics platform for equipment asset health analytics include the reduction of equipment failures, greater visibility of asset health (vs. targeted sampling), reduced expenditures on inspection programs through remote monitoring, and increased efficiency for engineering analysis.

Work Prioritization
The recently developed application for secondary network analysis assigns a priority score based on business rules to prioritize work to provide the greatest customer benefit. This provides benefits to spend capital more efficiently and reduce unintentional radial feeds to customers, which reduce outages. However, the business rules and prioritization parameters can be further optimized by using machine learning to establish correlations between system conditions and outages. This analytics tool will also provide benefits by linking secondary deficiencies across time to understand the cumulative impact of open mains, and where they should be restored most expeditiously. Even marginal improvements to the Company's allocation of capital for the secondary system, provides significant benefits given the size of the program.

Supplemental Information:

- Alternatives: An alternative to leveraging the enterprise analytics platform to model data and analyze business problems is to develop analytic applications in individual business areas. Failure to use an enterprise analytics platform could result in non-IT supported application development by individual departments that provide very limited scope and may not utilize the appropriate resources, data, and technology. These departmental projects consume capital funds, create new "silos" of data, may have redundant data and functionality, and ultimately require additional support personnel for administrative and maintenance activities.

Furthermore, if the data is not integrated to the enterprise analytics platform, it can't enable future unspecified use cases for that data, forgoing the network benefits of the platform.

- Risk of No Action: Not building advanced analytics capabilities would risk forgoing a powerful tool to optimize rules to run the business more efficiently and expand the visibility of engineers and operators. This would restrict the Company to using the existing toolset which will not keep pace with the rapid expansion of grid edge data. The Company would continue to manage by business rules and programmatic replacements and would not fully utilize the other advanced sensing and communications assets it is deploying.

- Non-financial Benefits: In addition to the financial benefits described below, the application of Grid Modernization use cases on EDAP offer additional non-financial benefits, including:
  - Risk reduction - By making use of additional grid edge data, the Company anticipates that it will be able to reduce public safety events and better maintain its equipment resulting in enhanced reliability for its customers
  - Customer satisfaction – The reduction of public safety events will lead to enhanced customer satisfaction
  - Compliance – The work management and asset maintenance enhancements will provide efficiencies in maintaining regulatory PSC compliance.

- Summary of Financial Benefits (if applicable) and Costs:
  Specific benefits associated with each use case include:

  Asset Health
  - Remote inspection offsetting manual inspection
  - Reduced transformer failures: Assuming ten less transformer failures per year, those attributed to corrosion or leaking which would be detectable through analytics of pressure, temperature, and oil ("PTO") data.
  - Improved engineering efficiency: Assuming the manual analysis required to perform PTO switch checks and low priority remote inspections is avoided

  Work Prioritization
  - Improved capital allocation through optimizing the System Engineering Analysis & Program Optimization Tool ("SEAPOT") parameters

- Technical Evaluation/Analysis: Past experience with EDAP and Microsoft Azure big data and analytics platforms informs 1-2 use cases of the scale outlined above can be developed per year.

- Project Relationships (if applicable): The Grid Innovation data analytics use cases are dependent on several other investments to source, transfer, store, model, and analyze data. Smart Sensors and Transformers with PTO sensors collect additional field data to analyze. Communications infrastructure is required to transmit the data back to receiving systems for processing. The Analytics Center of Excellence supports EDAP and provides analytics resources for the implementation of use cases.

- Basis for Estimate: The estimated costs are based on number, size, and periodicity of data sources utilized by the analytics tool, the scope of analysis performed, the reports and dashboards utilizing the analysis, and the integration of the application to existing enterprise systems to apply the analytics to improve field work.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	70	82	67	83
M&S	-	-	-	-	-
A/P	-	1,490	1,490	1,490	1,490
Other	-	132	132	132	132
Overheads	-	310	298	312	296
Total	**-**	**2,002**	**2,002**	**2,001**	**2,002**

X	Capital
	O&M

2020 – Common

Project/Program Title	Enterprise GIS Implementation
Project Manager	Baeth Fanek
Hyperion Project Number	PR.23317459
Status of Project	Engineering/Planning
Estimated Start Date	January 1, 2019
Estimated Completion Date	December 31, 2024
Work Plan Category	Strategic

CON EDISON GEOGRAPHIC INFORMATION SYSTEM (GIS) IMPLEMENTATION BUSINESS PLAN

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Executive Summary

The energy landscape is changing. Customers expect more involvement in their energy choices, more clean energy options, and more resiliency in the face of increasingly extreme weather events. New technologies like distributed solar, electric vehicles, energy storage, smart appliances, and electric heating are reshaping how and when customers use energy. Advances on utility sided assets and information systems provide powerful tools to expand innovation on the grid, increase customer choice, and add resiliency to an already reliable system. New York State is leading the nation in advancing the clean energy future and grid innovation.

Con Edison supports the movement to a customer focused, clean energy future, and has developed programs to get there. The Company has put significant effort into assisting our customers become more energy efficient with their electric energy usage and is now developing programs to assist customers with their gas energy usage. The Company is also developing the tools to give customers the personalized, seamless, and dynamic service and information across different communications platforms they expect. In parallel, the Company has developed a Grid Innovation initiative that strengthens its core infrastructure and allows it to respond to events more dynamically.

The Company's proposed Enterprise Geographic Information System ("GIS") is at the heart of these efforts. Con Edison plans to upgrade from its static mapping systems that include department-specific GIS applications to a single dynamic Enterprise GIS available to all departments within the Company. An Enterprise GIS will catalog and record the specific location and operating characteristics of all grid-connected assets, whether Company-owned or third-party distributed energy resources ("DER"), and the Company's gas and steam infrastructure. This information will enable the Company to develop a single, up-to-date model of its electric, gas, and steam distribution systems.

Many of the Company's Grid Innovation initiatives, which are designed to achieve a bi-directional DER-enabled grid, depend on an Enterprise GIS. For example, an Enterprise GIS is a prerequisite for an Advanced Distribution Management System ("ADMS") that would run continuous load flow calculations to optimize system configuration and improve the Company's situational awareness. An Enterprise GIS is also a prerequisite for a fully functional Distributed Energy Resource Management System ("DERMS"). Con Edison currently has over 23,000 DER (like rooftop solar) on its system and expects an exponential increase to achieve environmental policy goals; DERMS will be an essential tool for monitoring, forecasting, dispatching, and planning for this existing and new DER. An Enterprise GIS will enable the Company to:

- Visualize grid variables, equipment condition, and geo-spatial position of assets;
- Develop accurate distribution grid models all the way to the customer meter;
- Calculate and visualize DER installations and hosting capacity;
- Integrate with the electric outage management system and improve gas outage management;
- Improve the time required for valve isolation traces on the gas system using built-in trace capabilities in the GIS to replace current manual processes;
- Enhance situational awareness to locate nearest assets and resources; and
- Use a state of the art mapping system through all aspects of planning and implementing work (from design, to construction, to asset documentation, to operations and maintenance) thereby streamlining what is today a labor intensive process to achieve internal productivity gains.

The Company will use the Enterprise GIS to develop up-to-date models of its system that reflect both Company assets and third-party DERs. The Company's control center will depend on these models to reliably operate the DER-integrated grid. These and other capabilities make an Enterprise GIS critical to building the distributed system platform ("DSP") envisioned by the New York State Public Service Commission's Reforming the Energy Vision ("REV") initiative. An Enterprise GIS will also enhance gas safety, an important public policy objective.

Con Edison will proceed with an Enterprise GIS in three phases for an estimated total cost of approximately $235 million. Phase 1 ($25 million) will focus on replacing the VISION Electric and Gas system and will combine the Company's low-tension electric and gas maps into a single, state of the art GIS system. Phase 2 ($83 million) focuses on integrating the electric primary feeders and high-tension maps into the new GIS system. Phase 3 ($125 million), which is outside the horizon of the Company's 2019 rate filing, integrates the Company's steam system and electrical conduits, including vacant and obstructed conduits into the new mapping system, and will provide enhanced capabilities to all systems. While the Company currently estimates that Phase 3 will cost $125 million, the Company has not yet fully designed and developed final cost estimates associated with migration of the conduit mapping system under Phase 3. Phase 3 is the most complex piece and, its final cost will be affected by rapid changes in how GIS technology is evolving, enabled by emerging technology trends in analytics, artificial intelligence, and cloud computing. While present estimates indicate that the Enterprise GIS would be Benefit Cost Analysis ("BCA") neutral, the Company anticipates additional benefits and will continue to refine its analysis in the future as this project progresses.

INTRODUCTION

Importance of GIS

Enterprise GIS is fast becoming standard technology for large utilities. Though Con Edison has been able to extend the life of the existing mapping system, it is becoming increasingly resource intensive and limiting to achieving the Company's goals. Based on our benchmarking exercise, most other major utilities in the United States have already implemented a state-of-the-art Enterprise GIS. Other major utilities have had an Enterprise GIS for at least five years, and many for more than 10, and their testimonials and product demonstrations are extremely compelling.

Some of the challenges that surfaced for Con Edison in past evaluations of upgrading to a GIS platform were the pace of technological change, the complexity of adapting legacy systems to a new platform, and the sheer amount of assets in our gas, electric, and steam systems that needed to be converted. Consequently, Con Edison was not an early adaptor of evolving GIS technologies. The technology has since become less expensive and simpler to integrate with other systems. With all that is on the horizon in terms of our changing energy landscape, we are moving to this platform now.

For companies that have adopted it, GIS has evolved from being a "mapping system" to an interconnected visualization platform that is a central component of both operations and asset management. Con Edison's current mapping applications do not provide the capabilities of GIS technology.

Once implemented, the Enterprise GIS will be the cornerstone for Con Edison's Grid Innovation and customer experience efforts. The Company's Advanced Metering Infrastructure ("AMI") program and enhancements in its communication infrastructure will allow real-time data to feed into the Enterprise GIS, which the Company can then use to assist with outage management. Control Center personnel will be able to see a live map of existing outages and can better direct crews to return customers to service faster. In addition, the Enterprise GIS will allow the Company to produce models that reflect data from its distribution assets, AMI meters, and DERs connected to the system. With these models, Con Edison can more efficiently plan, design, and better operate the grid and its gas and steam systems. In short, the Enterprise GIS will touch on all aspects of the Company's operations.

Scope of Con Edison Systems

Maintaining detailed and accurate mapping systems is critical to Con Edison's ability to safely, reliably, and efficiently operate, maintain, and plan for its extensive electric, gas, and steam systems. Con Edison's maps are used to catalog literally millions of assets in every street in our service territory, and are critical to maintain, repair, and operate the system as well as account for these assets (property records) from a financial and tax perspective.

Electric System

Con Edison's electric system provides service to approximately 3.46 million customer accounts in New York City and Westchester County, which together have a population of almost 10 million. The Company's electric service territory covers 604 square miles and includes all of New York City, except the fifth ward (Rockaway Peninsula) in Queens, and approximately two-thirds of Westchester County.

The electric delivery system is comprised of approximately 96,300 miles of underground transmission and distribution lines and over 34,400 miles of overhead lines. Con Edison's service territory, while relatively small geographically, represents approximately 40 percent of New York State's peak electricity demand.

The Company's transmission system includes both underground and overhead infrastructure.[1] Con Edison's underground transmission system is the largest underground transmission system in the United States and delivers electric energy at 69 kilovolts ("kV"), 138kV, 230kV, 345kV, and 500kV. The overhead transmission system, located in Dutchess, Putnam, Westchester, and Richmond Counties, consists of 1,220 towers that support 355 circuit miles of cable situated along 113 miles of right-of-way. The Company also owns or jointly owns 387 structures that support 81 circuit miles in Orange and Rockland counties.

The Company's transmission and area substations consist of equipment (circuit breakers, transformers, series and shunt reactors, phase angle regulators, switches, relay systems, and communications systems) that are used to transform, sectionalize, control, and direct power on the electrical power system. Transmission substations receive power from generators or transmission lines and step the voltage down using transformers to deliver electric power to the area substations. Area substations receive power from the transmission stations and further step the voltage down to deliver electric power to the distribution system. The Con Edison system has 39 transmission stations and 62 area substations.

Con Edison's 62 area substations supply 65 networks and 19 non-network load areas. The distribution system is composed of network and non-network systems operating at voltages of 4kV, 13kV, 27kV and 33kV. Approximately 2,300 primary voltage distribution feeders supply network and non-network load.

Con Edison's underground distribution system is the largest underground, low-voltage, network system in the world. It includes approximately 266,000 manholes and service boxes; 25,400 conduit miles of duct; 96,300 miles of underground cable; and 42,500 underground transformers that further step the voltage down to supply the low-voltage secondary distribution system.

The Company's (non-network) overhead distribution system includes 192 auto loops; 217 unit substations; 13 multibank substations; approximately 198,700 poles; 51,800 overhead transformers; and approximately 34,300 miles of overhead wire including primary, secondary, and service wire.

Gas System

A gas distributor since 1823, Con Edison currently provides natural gas service to more than 1.1 million customers in Manhattan, the Bronx, the first and third wards of Queens, and Westchester County. The Con Edison natural gas transmission system is supplied by seven major gate stations and its northern distribution system is supplied by an additional four gate stations fed from various external interstate transmission pipeline companies. The Con Edison gas system also uses a shared inter-utility pipeline across its service territory that links us through two metering station interconnects with National Grid NY and LI, maintains eight underground utility tunnels that house electric, gas, steam, and communications pathways, and operates one liquefied natural gas plant.

[1] The Company has a GIS system for its transmission system that will interoperate with the new Enterprise GIS system but would remain separate for security reasons.

Con Edison manages a large, complex underground natural gas transmission and distribution system. This system contains approximately 4,400 total miles of gas main with approximately 375,000 service pipes that transport more than 330 million dekatherms of natural gas each year. The approximately 4,400 miles of gas mains consist of 94 miles of transmission mains operating at pressures greater than 125 psig and 4,300 miles of distribution mains operating at pressures less than 100 psig. Approximately 300 miles are large-diameter distribution mains, greater than or equal to 16" that mostly connect the transmission mains through multi-stage pressure regulators to approximately 4,000 miles of smaller-diameter distribution mains. Three hundred and thirty three pressure regulators across the system step the pressure down from transmission to high to medium to low in various parts of our system.

The Company is tracking the installation and location of every fuse made on its distribution system, in accordance with Public Service Commission requirements. Consistent with the Company's main replacement program, which involves installing almost 100 miles of new gas mains per year until 2036 in order to replace smaller diameter cast iron and unprotected steel materials, and in tandem with new customer connections, the Company has and will continue to install about 100,000 fuses per year. To maintain asset integrity, the Company must track fuses. The Company plans to integrate this information into GIS; until then, it is stored in a separate data warehouse. The ability to visualize these assets and incorporate them into one system is a benefit that will come with the new Enterprise GIS system.

Steam System

Con Edison's steam system is the largest district steam system in the United States. A district steam system generates steam at central plants and distributes it through a network of underground pipes directly to buildings. Con Edison owns and operates five steam plants and 105 miles of underground steam mains and service pipes in Manhattan. In addition to its own facilities, the Company has a long term steam supply contract with Brooklyn Navy Yard Cogeneration Partners. The Company's steam system runs from Battery Park at the southern tip of Manhattan to 96th Street on the West Side and 89th Street on the East Side.

Current Mapping Systems

The Company's current mapping system consists of five major systems and 32 ancillary systems. The five major mapping systems are outlined in the table below.

#	Major System	Function	Region
1	VISION	Electric Secondary	Brooklyn/Queens, Bronx/Westchester, Manhattan
		Gas	Bronx/Westchester, Manhattan, Queens
		Conduit	Brooklyn Only
2	Electric Primary	Electric Primary	Brooklyn/Queens, Bronx/Westchester, Manhattan
3	EDFIS	Electric Primary, Secondary & Conduit (Staten Island mapping)	Staten Island Only
4	Conduit & Duct Occupancy	Electric Conduits & Structures	Brooklyn/Queens, Bronx/Westchester, Manhattan
5	SOMIS	Steam Operations Mapping and Information System	Manhattan Only

Business Drivers for Enterprise Wide GIS

The Company's five major mapping systems and 32 ancillary mapping systems are functionally redundant. Combined, they use 15 distinct and proprietary coordinate systems with outdated graphical user interfaces. These systems have redundant data and are costly to maintain or enhance and require Information Technology ("IT") to maintain expertise in outdated technologies. The Company's continued use of its current mapping and visualization systems limits business effectiveness and capabilities including:

- **Collaboration with Federal, State, Local government agencies during emergencies** – The proprietary coordinate systems and obsolete data formats of the current mapping systems limit the Company's ability to share facility location information with external stakeholders. More importantly, these systems restrict the Company's ability to leverage the multitude of geospatial data services published by government entities including the City of New York, Westchester County, Federal Emergency Management Agency ("FEMA"), the Census Bureau, and the National Weather Service.

- **Multi-commodity maps** – The current mapping systems do not effectively display all commodities in a single view. As a result, significant effort is required to acquire and reconcile multiple map products during planning, design, and construction activities. When new electric and gas assets are added, these are recorded multiple times in the current systems.

- **Lack of automation** – For each completed work request or data correction request, asset mapping data must be manually entered into three systems. This introduces data discrepancies between the respective systems.

- **Lack of new capabilities** – Incorporating new and much needed functions and features into the current mapping systems is a complex and costly undertaking due to the number of systems and their obsolete technical environments. For instance, new GIS would enable Distributed Generation ("DG") hosting capacity maps to be updated more quickly.

- **Ad-hoc map production** – Substantial effort is required by IT to produce specialized maps. The future Enterprise GIS will provide end users the ability to develop ad-hoc thematic maps, which will incorporate internal and third-party map layers.

- **Limited functionality** – Existing systems have limited functionality, such as the inability to plot maps from an end user device. The existing mapping systems have limited mobile device functionality. This capability is deployed through conversion of our asset data on mobile software platforms at increased costs and reduced functionality.

- **Redundant data entry & maintenance** – Presently, the Company enters the same data multiple times into three separate mapping systems. This adds to the amount of time required to post data, creates the potential for error, and delays the availability of data for external systems, such as the electric Outage Management System - System Trouble Analysis & Response ("STAR") and Load Flow Modeling System -Poly Voltage Loadflow ("PVL"). An Enterprise GIS, with a central geo-database, offers potential savings through efficiency gains and reduction in support costs.

- **Limited Technical Expertise** – The Company has limited specialized resources with skills to support these obsolete platforms. The technical skills required to maintain and support these systems are not readily available in the market due to limited use across the industry and aging technology.

- **System Failure & Recovery Times** – In the event of catastrophic hardware failure or software malfunction, current mapping systems may become inoperable, increasing recovery time and impacting critical business operations. The risks associated with relying on these unsupported products increase over time, as the underlying operating systems are discontinued.

Department-Specific GIS Related Applications

The Company's current mapping system was designed to meet the needs of individual departments. Sixteen Company departments have developed their own GIS related capabilities for their own use. A few examples include:

- Construction Business Services uses a custom application that is designed to show the Company's proposed excavating work in real world coordinates in conjunction with New York City's paving schedule. This functionality is relatively easy to configure in the web-based visualization component of the planned Enterprise GIS.

- Construction Management uses a survey base map to capture Company underground structures with survey grade accuracy. The base map is utilized by regional engineering groups when issuing a layout for new underground structure and conduit. This base map functionality will be incorporated into the Enterprise GIS base map layers mitigating the need for a standalone application.

- The Electric System Damage Assessment application was developed following Hurricane Sandy to visualize overhead distribution feeders to improve the damage assessment information gathering process. This application was developed on a custom product platform and requires specialized technical resources to administer and maintain this application.

Some of these GIS related applications are supported by specialized business led IT teams and are limited by the specific department need that required them. None of the existing GIS-related applications provide an interconnected model for use across the engineering departments and operational systems. This departmental level approach does not effectively leverage resources and increases total cost of ownership due to:

- **Increased software licensing costs** – Multiple departments purchase software license and maintenance agreement, from same product vendors rather than using a single corporate licensing arrangement.

- **Functional and data redundancies** – Departmental solutions are not designed from an enterprise perspective and do not share computing, database or technical resources.

- **Inconsistent product architectures** – The current applications do not leverage a common GIS platform architecture and consequently support, and training costs are increased.

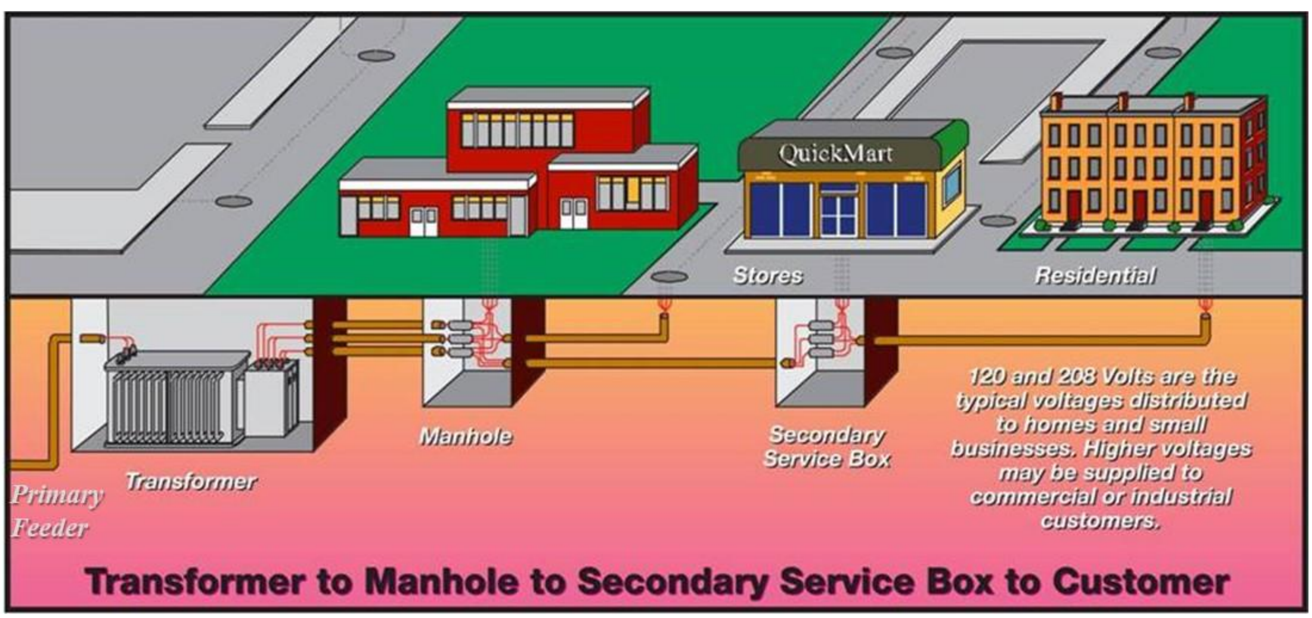
ENTERPRISE WIDE GIS IN ACTION

An Enterprise GIS will allow the Company to combine multiple maps into a single model. This section presents an example of what that means for the Company's electric distribution system.

The Company relies on three major mapping systems for its electric distribution system. The Electric Primary system, which maps primary feeders, VISION, which maps the secondary system and is also utilized by Gas, and Conduit & Duct Occupancy, which maps the underground structures that house electrical components, like transformer vaults, manholes and service boxes. Staten Island is an exception; there, all three systems are combined on the EDFIS system. The steam system is another exception and has its own mapping system. Adding these two exceptions totals to the five mapping systems shown in the table above and the plan is to also integrate these two exceptions into a single GIS platform.

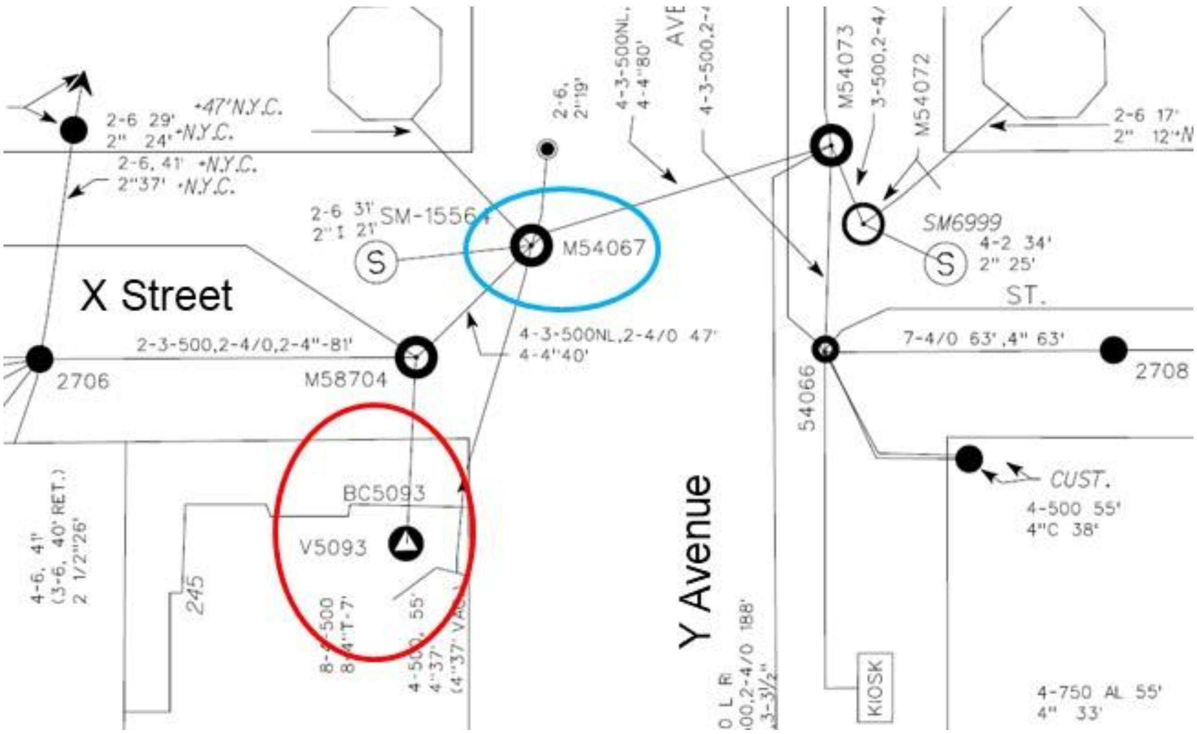
The figure below is a simplified, graphic illustration of the Company's underground electric system; the Company relies on three major mapping systems to depict the different elements of the underground electric system that make up this illustrative graphic.

In this figure, the primary feeder (which would be delivering power at 13,800 volts in Manhattan) delivers power from the left side of the transformer (*i.e.*, the primary side) to the right side of the transformer (*i.e.*, the secondary side). The transformer takes the primary feeder voltage of 13,800 volts and transforms it down to the secondary (also the delivery) voltage of 120/208 volts where it is routed through the streets to manholes, then to customer service boxes and then ultimately to the customer premise. Historically, it has been easiest to segment these components into the primary feeder system, the secondary electrical system, and the conduit system which would include the manholes, service boxes and transformer vaults that house the equipment; the mapping system is designed in the same fashion.

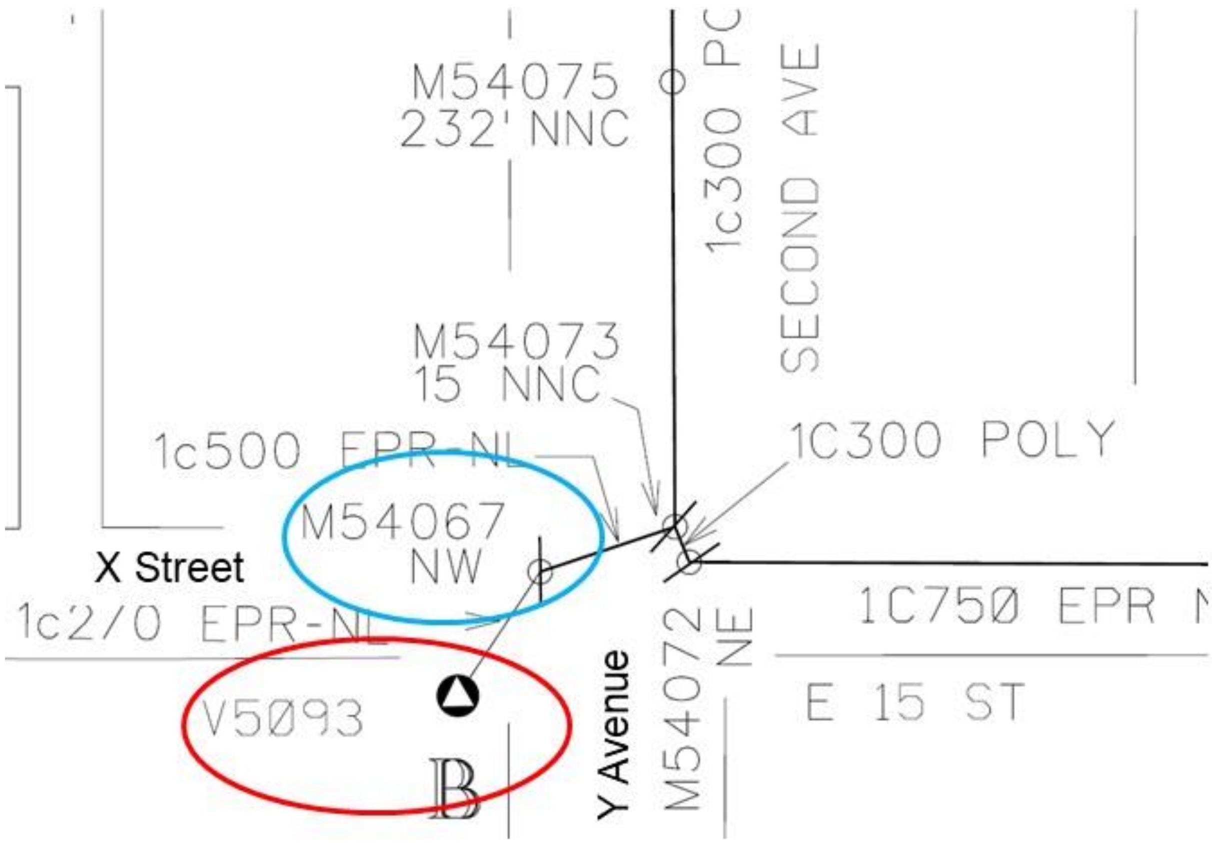


To demonstrate the historical benefit of having three mapping systems (prior to GIS being available), the elements of a representative common street intersection (called X Street and Y Avenue in this example) are shown on all three electrical mapping systems:

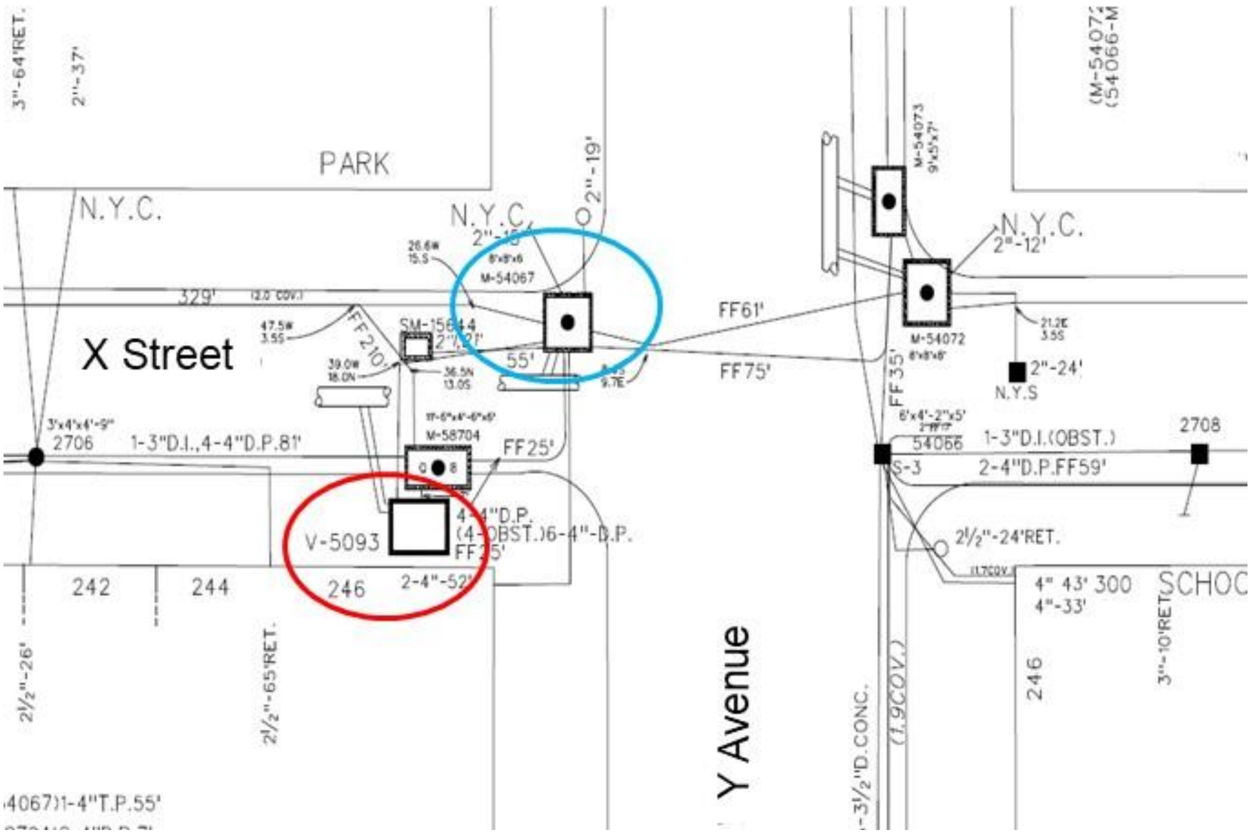
1. The VISION mapping system (which depicts the electric secondary system sometimes referred to as the network or grid) depicts the 120/208 volt delivery system and displays the vast majority of the Company's structures. Unlike the conduit maps described below, these maps are not drawn to scale but attempt to be spatially correct.



2. The Electric Primary mapping system displays a schematic of the primary feeder and is used mostly to provide safety to Con Edison personnel working on the primary voltage system (in this example, the 13,800-volt feeders and associated equipment). As schematics, these maps are neither drawn to scale nor spatially close to actual field conditions (thisis intended and appropriate for this set of maps). These maps are also used to inform our load flow models, as will be discussed in more detail below.



3. The Conduit and Duct Occupancy mapping system displays the structures that house the electrical equipment and is critical for construction work. These PDF maps are drawn to scale and are the most detailed with respect to structure size, curb lines, street lines and property demarcations.



In each of the figures above, common elements like manhole M54073 (circled in blue) and transformer/transformer vault V-5093 (circled in red) are identified. Since the primary feeder map is simply a schematic that helps operators and maintenance employees identify how to safely work on equipment, it is not to scale and only displays components specific to that feeder (for example, there are no service boxes on primary feeder prints because services boxes are used exclusively to deliver secondary voltage to customers). The VISION (i.e. mains and secondary) mapping system and conduit system both show all the structures involved, providing much more detail on the streets and buildings and, in the case of the conduit maps, are drawn to scale. The Company developed these maps long before computers existed and they were originally developed separately because of the extensive information required in every street and the need to provide them on a sheet of paper that could be carried and handled by field personnel. When they were eventually digitized, computational capability at the time only allowed for static pictures so the format remained the same. A GIS mapping system allows us to "layer" these maps within a single mapping system (along with gas, steam and whatever other mapping system we choose to interface with that is spatially correct) and "turn on" and "turn off" only the layers we need to see.

The VISION mapping system serves an additional function of providing all the electrical data to our advanced load flow models that are used for both planning and operations. As such, upgrading our VISION mapping system to a GIS mapping system platform is the most logical starting point and yields the most immediate benefits. In addition, the VISION system's underlying technology ("FRAMME") has a remaining domestic user base of four sites including Con Edison.[2] All other sites are in the process of implementing system replacements. The product vendor (Intergraph) has discontinued new capabilities to the product.

[2] As of January 2019 Los Angeles, Department of Water and Power ("LADWP"), and Oncor utilize FRAMME technology with planned migrations to GIS technology beginning 2020.

PROJECT BENEFITS

An Enterprise GIS is necessary to unlock the benefits of the customer focused, clean energy future both New York State and the Company are seeking to achieve. An Enterprise GIS enables resource sharing, data organization, and improved decision making. An Enterprise GIS will provide precise and meaningful business intelligence solutions for effective asset and resource management and delivering safe and reliable services to our customers.

Grid Innovation

Many of the Company's Grid Innovation initiatives, which are designed to achieve a bi-directional DER-enabled grid, depend on an Enterprise GIS. The Department of Energy's DSPx Modern Grid Distribution Project has identified GIS technology as foundational to grid innovation in the United States.[3] An Enterprise GIS is a prerequisite for an Advanced Distribution Management System ("ADMS") that would run continuous load flow calculations to optimize system configuration and improve the Company's situational awareness of grid and customer assets. An Enterprise GIS is also a prerequisite for a fully functional Distributed Energy Resource Management System ("DERMS"). Con Edison currently has over 23,000 DER (like rooftop solar) on the Company's system and expects an exponential increase to achieve environmental policy goals; DERMS will be an essential tool for monitoring, forecasting, dispatching, and planning for this existing and new DER. In addition, an Enterprise GIS will enable new grid capabilities that include:

- **Grid Visibility & Monitoring** – With the availability of geo-spatial data on our assets, grid operators will be able to visualize grid variables and equipment conditions. Advanced grid monitoring and operator tools depend on robust visualization tools enabled by GIS technology.

- **Grid Modeling & Simulation** – Interconnected grid models with AMI data and DER assets will enable end to end load flow modeling all the way to the customer meter for seamless functionality between the grid and customer technologies. The Enterprise GIS will increase the quality of data used by engineering load flow analysis systems such as electric Poly Voltage Load flow (PVL) and gas SynerGEE, reducing the time required to prepare data for import into planning and analysis systems. The Enterprise GIS system will also improve the efficiency of isolation traces using built-in trace capabilities in the GIS and improving the accuracy of gas load flow models.

- **Grid Planning** – The Enterprise GIS platform will enable spatial analytics to improve grid reliability planning. For example, Company engineers can visualize historical electric and gas outages across the entire system to identify low reliability areas for planned investments that coincide with New York City and Westchester County's planned infrastructure projects to reduce costs. Over time spatial analytics enabled by machine learning tools will improve grid asset management capabilities.

- **Grid Hosting Capacity** – Interconnected grid models will improve the accuracy of the impact of the DER installations and increase the accuracy of the hosting capacity.

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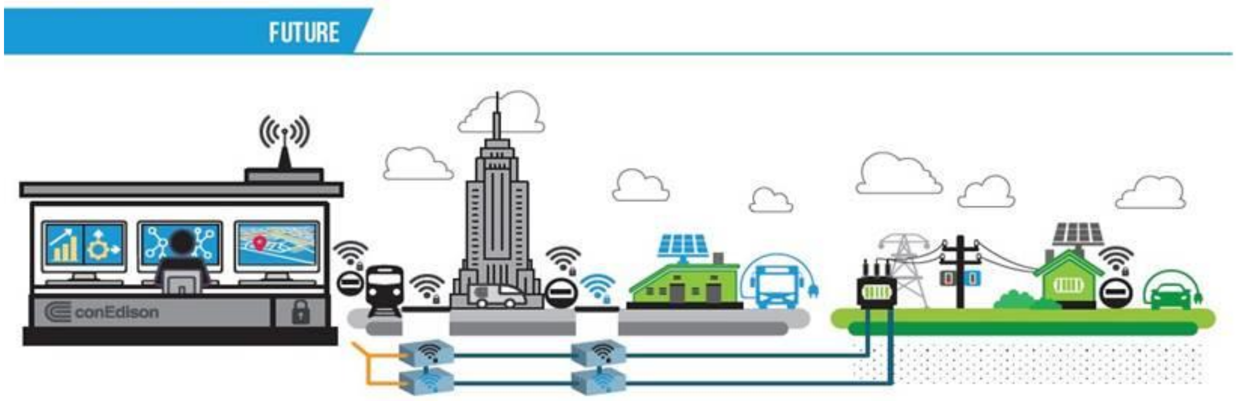
[3] https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

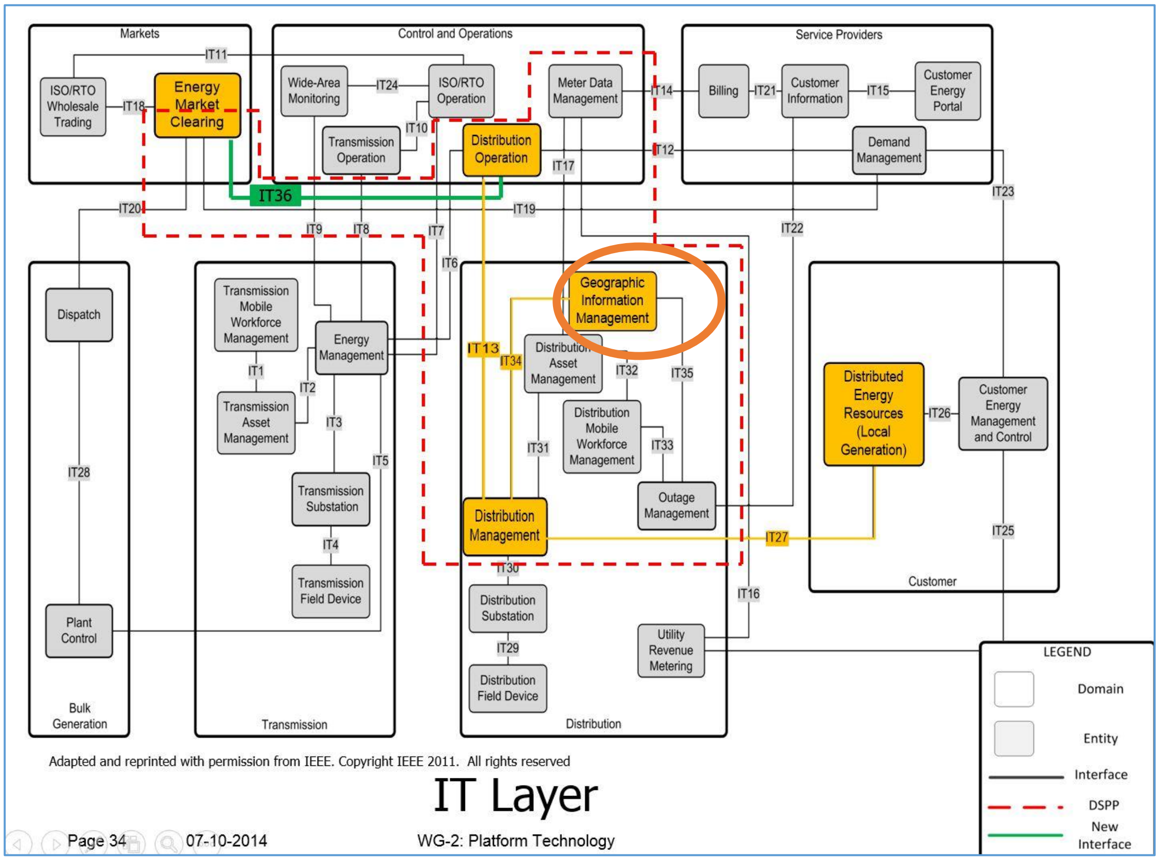
- **Grid Operation** – Enterprise visualization platform enabled by the Enterprise GIS will be integrated with the electric and gas outage management systems to provide operators near real time visibility on grid conditions and enhanced situational awareness to dispatch resources to nearest assets.



Reforming the Energy Vision (REV) Goals

Working Group 2 of the Public Service Commission's "Reforming the Energy Vision" (REV) initiative previously issued a final report that identifies the required technology to enable the transition of New York's electric utilities to "Distribution System Platform Providers" (DSPP).[4] GIS is one of the platform technologies included in the report (see figure below). It is an accepted industry practice to maintain comprehensive facility models in GIS – models that are required by multiple operational systems including ADMS. In addition, GIS is an effective tool for aiding in the communications infrastructure planning and monitoring the deployment of AMI solutions.

[4] PSC Working Group 2 Platform Technology Final report, July 8th, 2014
https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/853a068321b1d9cb85257d100067b939/$FILE/WG%202_Platform%20Technology_Final%20Report%20&%20Appendices.pdf



PSC Working Group 2 Platform Technology

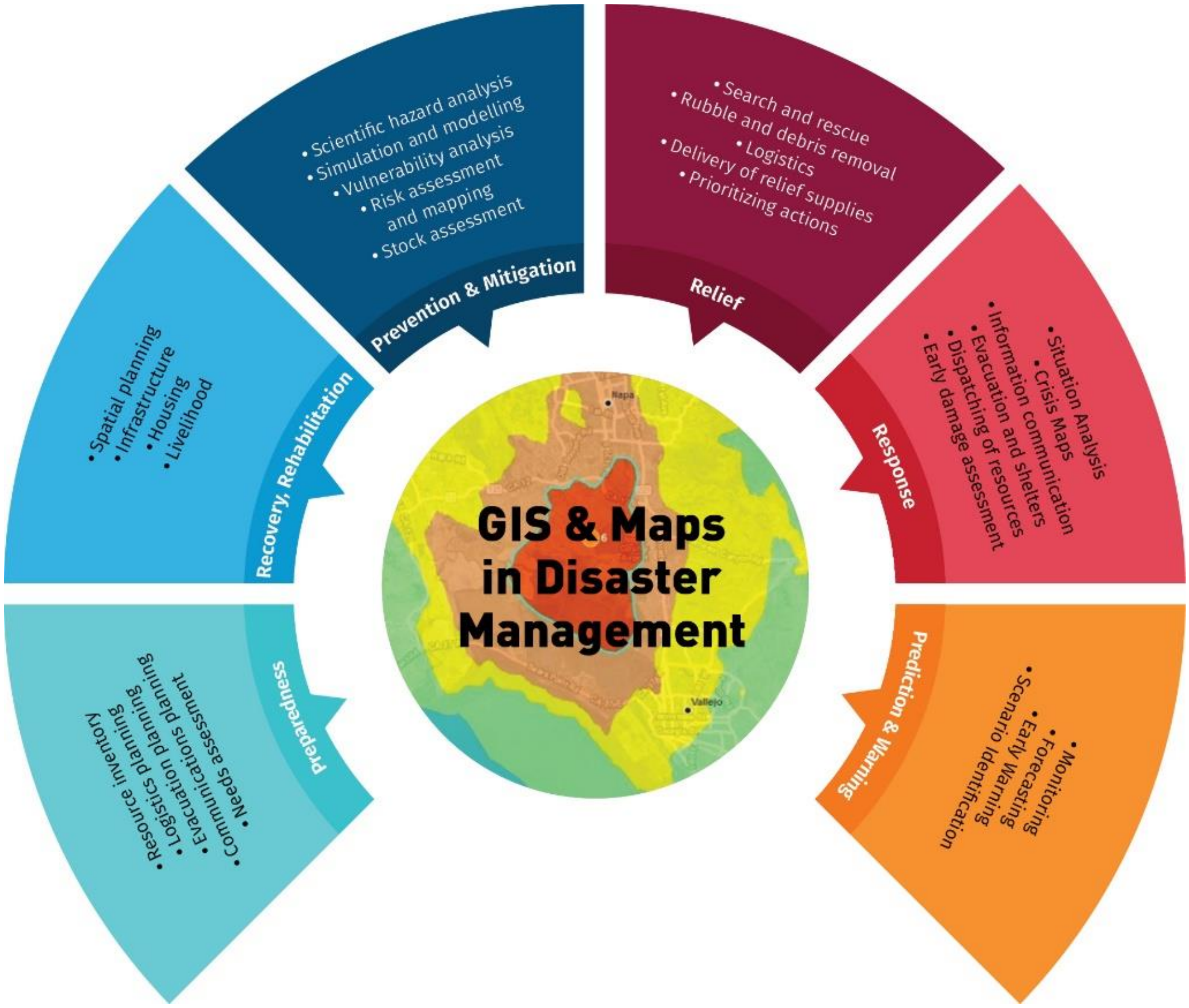
The up-to-date, real-time system model produced by an Enterprise GIS is required for the Company to meet long-term REV initiatives, including establishing the DSPP, and facilitates timely and current load flow modeling that control center personnel will depend on in the future.

Additionally, distribution circuits will become vastly more complex to plan and operate due to the continuous integration of DERs. One of REV's goals is to defer utility spending on capital reinforcement of these circuits by way of non-wires solutions. An Enterprise GIS will improve the accuracy of load flow modeling to streamline the benefits of siting non-wires solutions. REV will also enable more customer-centered initiatives including time of use rates, more customer energy choices and programs, and customer access to load data to better manage their usage. An Enterprise GIS will provide a single integrated platform for managing and disseminating the requisite network models and provide employees access to geospatial data from a suite of centrally managed applications.

Emergency Planning & Response

The modern GIS technology is steadily transforming the capabilities to respond to major events. Hurricane Sandy heightened the use of GIS by federal, state, and local governments in the northeast. For example, New York City recently established a Disaster Assessment and Power Restoration Plan, which incorporates GIS at the center of response planning, field assessment, and public outreach. In addition to the telecoms and peer utilities, Con Edison is a participant in this plan.

This and similar programs in Westchester County present an opportunity for outage management and municipal collaboration.



Emergency planning and response rely on geographic information to predict areas that are most at risk. An Enterprise GIS will enable the Company to share spatial information about assets affected by events with the New York City Office of Emergency Management ("OEM") and Westchester County to prioritize relief efforts. In general, emergency management services increasingly rely on GIS platforms to generate crisis maps based on a combination of satellite imagery, remote sensor readings, statistical models, and crowdsourced data. For instance, utilities and first responders use spatial analysis of utility assets and customer social media posts to create a map of locations in urgent need of relief during storms. Robust and accurate geographic information is necessary for first responders to make well-informed decisions, and ongoing refinements to real-time data analysis are increasing GIS accuracy. Enterprise GIS would allow the Company to deploy turn-key mobile applications during emergencies. Such mobile apps have been deployed during recent major events such as Hurricane Harvey and the Northern California Campfire.[5]/[6]

[5] 3 Ways GIS Is Changing How We Respond to Hurricanes: https://www.govloop.com/gis-is-changing-how-we-respond-to-hurricanes/

Employee & Public Safety

Enterprise GIS platform integration with the Company's Outage Management System (OMS) and Supervisory Control and Data Acquisition (SCADA) system will enable electronic switching orders for electric distribution circuits and replace a manual process that can lead to operating errors. The built-in visual trace capability inherent to modern GIS platforms improves the safety and reliability of gas and electric distribution circuits through validation of circuit continuity and reducing mapping errors.

Con Edison electric and gas crews will benefit from an Enterprise GIS system by being able to more readily view field hazards/conditions as a layer that is available on the GIS visualization platform. For example, today, electric crews are often dispatched and arrive to find that the structure cannot be worked on due to a safety hazard. Having an integrated Enterprise GIS will allow for any field safety hazard or "D" fault to be tagged to the asset. For example, should a feeder joint be "D" faulted, the mapping system will allow for that structure to be displayed as "tagged". This status would be immediately reflected to all users and displayed on all map products. This will yield efficiency by eliminating the unnecessary dispatching of a crew(s) to hazard locations. Other examples of potential field hazards include, environmental (oxygen deficient or hydrogen sulfide in structures) or structural (condemned due to structural defects) hazards. The Company would also be able to share this data with other City agencies in spatial format.

Grid Resilience

An Enterprise GIS will improve grid resilience and reduce outage restoration times. Some of these benefits include:

- **Vegetation Management** – An Enterprise GIS will enable new spatial analytics capabilities combined with accurately mapped facilities that will enable efficiency gains in the planning and tracking of vegetation management to reduce unplanned outages. In addition, the Enterprise GIS will provide the capability of targeting vegetation management based on circuits and migrate to condition based vegetation management program vs. time-based program thereby optimizing investments. Enterprise GIS will enable integration of LiDAR technology to enhance vegetation management programs in the near future.

- **Outage Management** – Enterprise GIS will improve the accuracy of outage counts in the OMS system and facilitate faster restoration of customer outages during normal blue-sky events as well as major storms. Combining geospatial visualization of AMI data with predictive analytics tools is enabling utilities to reduce the duration of the outages from weather events and identify weak points in the electrical distribution system to prevent future outages.[7]

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[6] How GIS was used in the response to the 2018 Northern California wildfires: https://inpublicsafety.com/2018/11/gis-technology-aids-in-effective-response-to-california-wildfires/

[7] Weathering the Storm: Using Predictive Analytics to Minimize Utility Outages. Kathy Ball, SAS Institute: Mark Konya, Ameren Missouri. Paper 232-2013. http://support.sas.com/resources/papers/proceedings13/232-2013.pdf

- **Damage Assessment** – Enterprise GIS will allow the Company to deploy a standardized damage assessment tool that will seamlessly integrate with our existing OMS and WMS systems to increase operational efficiency.

Enterprise GIS for Gas

An Enterprise GIS also benefits the Company's gas system. With an Enterprise GIS, Gas Operations will be able to reduce excavation risk and operating errors, engage in real-time collaboration with City agencies when responding to gas public safety incidents or coordinating planned work, more efficiently monitor the performance of gas transmission and distribution systems, and better manage gas outages and restoration efforts. Gas Operations could also have potential integration opportunities with AMI to monitor system performance at the service level. Additionally, the Company could create gas flow modeling and simulations for planned and emergency work. An Enterprise GIS would also provide a gas system inventory which will give the Company the ability to trend data and analytics required to identify threats for our Distribution/Transmission Integrity Management Programs, as well as ad-hoc reporting.

Customer Experience

Con Edison, as the Distributed System Platform Provider (DSPP), remains committed to increasing the amount of data available, making it easier to access system data through its online portal, and supporting stakeholder data needs. An Enterprise GIS will allow for future use cases for system data availability, identify additional datasets to share, and respond to stakeholder requests to improve ease of access to system data. The Company currently provides extensive system data as part of the hosting capacity platform within the system data portal. The existing hosting capacity maps are customized web-based GIS format to show locations where it is beneficial to interconnect distributed generation. With continued enhancements to the Enterprise GIS through the phased implementation, the Company will continue to provide useful information to customers and developers looking to interconnect to the Con Edison distribution system. A few use cases include:

- GIS platform will enable asset management capabilities for all assets behind the meter and reduce the time needed to analyze grid impact of citing DER resources.

- Spatial proximity analysis of new electric and gas service requests within existing infrastructure will reduce the time for new business and DER requests.

- The current systems proprietary coordinate systems and obsolete data formats substantially inhibits the Company's ability to exchange and/or integrate third party data. The Enterprise GIS technology uses Application Programming Interfaces (API) architecture that will provide the ability to incorporate data from external entities into dynamic map displays. Examples of available data include New York City / New York State / FEMA "GeoHub" portals, public improvement job sites, contractor drawings, parcel/cadastral data, flood zones, census bureau zones, and associated demographic data.

Single Source of Information

The Enterprise GIS will provide efficiency gains associated with mapping, facility records management, and data analysis. At the end of the project, the Company will create a single reliable source of information for all the Company's assets and customer assets that interoperate with the grid.

- Data integrity and accuracy will improve as mapping teams will update a single system at work order completion, instead of multiple systems (Primary, Secondary, and Conduit) once all three phases are completed. There will no longer be a need to maintain composite feeder maps in Manhattan and the Bronx and Conduit and Duct Occupancy maps (cable updates only) for Westchester, Brooklyn and Queens.

- GIS integration with electric and gas WMS will mitigate the need for redundant data entry and improve accuracy for electric and gas work orders.

- Enterprise GIS will simplify the mapping and data updates associated with large load transfers, and network splits that require significant time.

Cost Reduction

Consolidating the mapping applications into an enterprise wide GIS platform will reduce total cost of ownership. Cost efficiency gains include:

- **Software licensing and infrastructure costs** – These costs are higher for unsupported mapping systems due to need for custom support and with no additional functionality. Mitigation of cybersecurity vulnerability with unsupported infrastructure components require additional investments that affects end users access to these systems and increases support costs. Migrating to enterprise wide GIS will allow the Company to consolidate the mapping systems and reduce software and hardware costs associated with multiple systems. Deploying an Enterprise GIS platform will allow the Company to develop strategic partnerships with vendors to standardize technology platforms and effectively manage support costs.

- **Reducing non-Enterprise GIS applications** – An Enterprise GIS will reduce costs and streamline business processes by using Company-wide application platforms. Enterprise wide GIS platform will reduce the segmentation of the application portfolio and matching support levels to system needs.

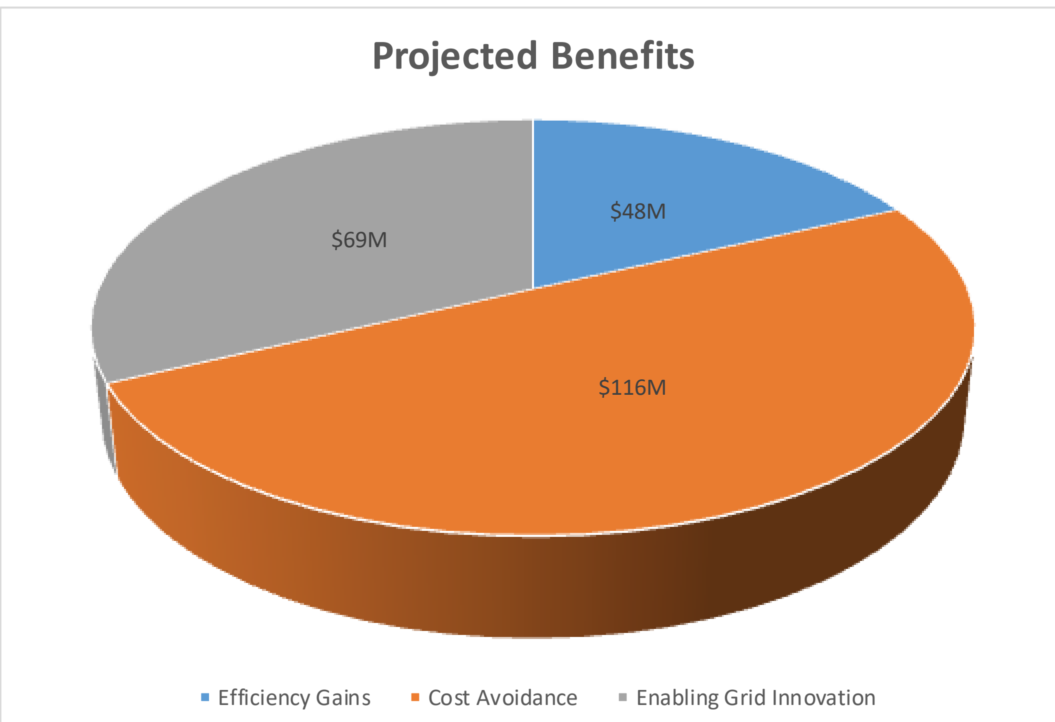
- **Support costs** – An Enterprise GIS will reduce costs associated with training and sourcing of limited resources supporting outdated mapping technology platforms. An Enterprise GIS platform will allow the Company to focus talent on the highest value work, such as technology enablers, and using vendors for standard work. Standardizing common mapping tools will also lower support costs by mitigating the need for custom tools.

- **Software integrations** – Software integrations with obsolete outdated mapping platforms increase implementation and operational costs of operational utility systems such as WMS, OMS etc. Enterprise GIS will reduce the integration costs of future software platforms as well as improve the availability and security of these platforms by replacing non-standard integrations. Enterprise GIS will reduce cybersecurity risks due to obsolete technology, promotes enhanced infrastructure utilization.

Cost Benefit Analysis

The Company is estimating $233 million in benefits over a 20-year period from the deployment of the Enterprise GIS. Efficiency gains include reduced costs associated with maintaining outdated technology, standardization of non-enterprise GIS applications, integration with other systems, and mapping efficiency. Cost avoidance includes avoided costs associated with improved electrical and gas spatial analysis, vegetation management efficiency, implementing energy efficiency programs, capital work layouts, and enabling DSP. While an Enterprise GIS offers several quantifiable benefits, there are many qualitative benefits that GIS enables through other Grid Innovation initiatives such as DERMS, Voltage Var Optimization ("VVO"), and ADMS, totaling gross benefits of approximately $69M over a twenty-year period.

The Company utilized the BCA methodology developed collaboratively by the Joint Utilities under the Commission's Order Establishing the Benefit-Cost Analysis Framework (BCA Order). This methodology and the associated templates have been combined with Company-specific data to develop Con Edison's BCA Handbook. The Company used the BCA Handbook, the most recent update of which was filed in July 2018, to assess the Company's Enterprise GIS investment. The chart below, summarizes the cumulative estimated benefits of cost avoidance, efficiency gains, and enabling grid innovation for deploying Enterprise GIS at Con Edison in phases.



Advanced Future Capabilities

With the increase in the availability of spatial data, GIS enabled solutions are driving new capabilities for utilities. The global GIS solutions market is expected to reach $17.3 billion by 2023 according to

P&S Market Research.[8] GIS investments are providing substantial positive payback across the industry. For example, King County, WA has undertaken a GIS ROI Study where the County has realized $775 million from its GIS investments.[9] Future use cases for Con Edison include:

- **New York State Smart Cities Initiative** – Con Edison's GIS implementation will support New York City's initiative to develop the Subterranean Information Model that includes all utility and city assets that allows all stakeholders access to buried infrastructure.[10] There is a strong business need to map underground infrastructure, but it is limited by availability of spatial data and the security concerns associated with sharing the data amongst facility owners. Securely incorporating asset data into this model will allow the Company to identify its infrastructure amongst all the buried infrastructure.

- **Location Based Services** – GIS will enable real time location processing, which may allow the potential for incorporating autonomous vehicle locations in the future to automatically direct field crews nearest to a job. This could enhance post-disaster outage recovery operations and enable customers to track utility restoration crews.

- **Artificial Intelligence** – Advancements in AI and machine learning (ML) enabled by cloud computing infrastructure will enable rapid integration of 3D (three dimensional) visualization tools on modern GIS platforms. Modern GIS platforms support integration of Virtual Reality ("VR") and Augmented Reality ("AR") to enable new capabilities. Artificial intelligence is another rapidly evolving technology that has been applied to GIS projects in recent years. For example, AR enabled 3D models of hazardous locations can be utilized for safety training of field crews.

- **Environmental Sustainability** – One important application for GeoAI[11] is in planning urban infrastructure and tracking changes in an area over time. For example, researchers in Los Angeles wanted to know how land use and roadways impacted air pollution and, in turn, how pollution would affect health in residents. GIS helped them analyze traffic patterns over different times of day in relation to the concentration of harmful particles in the air. By using this information to predict when pollution levels would become dangerous, the city could issue warnings as early as possible.

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[8] https://www.psmarketresearch.com/press-release/global-geographic-information-system-market
[9] https://www.kingcounty.gov/elected/executive/constantine/news/release/2012/April/05GISroi.aspx
[10] https://www.nytimes.com/interactive/2014/03/23/nyregion/the-network-of-pipes-under-manhattans-streets.html
[11] https://ecce.esri.ca/wpecce/2018/04/23/what-is-geoai/

SCOPE OF THE PROGRAM

Con Edison has initiated a phased deployment plan to consolidate the various mapping systems in stages that reflect the three primary mapping systems and deliver business benefits along the way. When complete, GIS will result in a single model that displays the Company's electric, gas, and steam distribution systems, with the capability to turn layers on and off so a user can see all or some of the data. All data and assets will also be displayed on a google based real word coordinate mapping application that allows the user to toggle on/off various mapping systems.

Phase 0

In 2014, the Company undertook a Phase 0 planning project for an enterprise wide GIS deployment. During this project, the Company engaged GIS product and data migration service vendors to:

- Conduct functional, data migration, and system integration workshops with subject matter experts from the electric, gas, and construction organizations and IT
- Finalize the electric and gas geospatial data models and perform a formal pilot data migration of all core mapping systems
- Develop functional requirements documentation for the GIS mapping, visualization and mobile product components
- Develop requirements for the integration of GIS with existing systems including STAR, Gas Inspection System, PVL, and Work Management System ("WMS")
- Conduct five pilot data migration, conversion, and data conflation[12] for Electric and Gas in Manhattan, Bronx, Westchester, Brooklyn and Staten Island
- Define implementation options and associated cost estimates
- Analyze Graphic Design products and estimate implementation costs
- Train the GIS Core Team in the future GIS product
- Update the GIS Business Case to reflect Phase 0 findings

In 2017, the Company expanded on Phase 0 to conduct additional data quality assessment and to evaluate the latest GIS technology. In 2018, the Company began competitive sourcing for parts of the project. The Company incorporated lessons learned and information gathered from Phase 0 into this business plan.

Phase 1

Phase 1 ($25 million) will focus on replacing the VISION system, which consists of the Company's low-tension maps for all electric customers supplied by 120V and 465V cables and all gas customers supplied by gas service pipes. Phase 1 will combine these Company electric and gas maps into a single, new GIS platform.

Phase 1 will occur from 2019 to first quarter of 2020. Benefits of Phase 1 include:

- New Mapping Tools for secondary electric distribution system and gas distribution
    - Spatial Asset Management Tool
    - Planning & Analysis tool

[12] In GIS, conflation is defined as the process of combining geographic information from overlapping sources to retain accurate data, minimize redundancy, and reconcile data conflicts.

    - Field Mobility Mapping Tool
- Create a new visualization tool
- Reduce secondary mapping and gas mapping backlogs
- Create asset management capabilities for example, DERMS, AMI, and MTA assets
- Enhanced Load Flow Analysis
- Retire CuFLink and APS applications
- Third party data integration e.g., NYC Open Data, Westchester County, Orange and Rockland Counties
- Enhance regulatory compliance for Gas through visualization of assets such as fuse tracking

Phase 2

Phase 2 ($83 million) focuses on electric primary feeders and high-tension maps. These maps include all cables and joints associated with our feeders. The EDFIS system consists of all high-tension maps in Staten Island, which currently use a different mapping application than the rest of the boroughs and Westchester County. The conversion of the high-tension maps will be added to the already converted low tension maps. Phase 2 will commence in 2020 and continue until the end of 2022. Benefits of Phase 2 include:

- New mapping tools for the Primary or feeder system
- Electric Primary, Secondary Connectivity Model
- Robust Enterprise Wide Spatial Analytics Platform
- Enable use of emerging technologies such as AR, VR, LiDAR, Drones etc.
- Location intelligence – autonomous vehicles and asset access
- Enhance regulatory filings for electric, construction, and gas; for example, the proposed Enterprise GIS platform would increase the accuracy of layout and drawings submitted for New York City and State permitting requirements.
- Enable REV DSP goals to share data with customers
- Reduce total cost of ownership for technology and create the opportunity for potential partnerships

In addition, Gas Operations will leverage functionality offered by the GIS system to enhance and support its work and asset management system implementation. These include out of the box features such as spatial views of flood maps, population data and other related demographics. Subsequent to the full deployment of its work and asset management system in 2020, Gas Operations will leverage lessons learned from Phase 1 to determine the implementation roadmap of Enterprise GIS with work and asset management system.

Phase 3

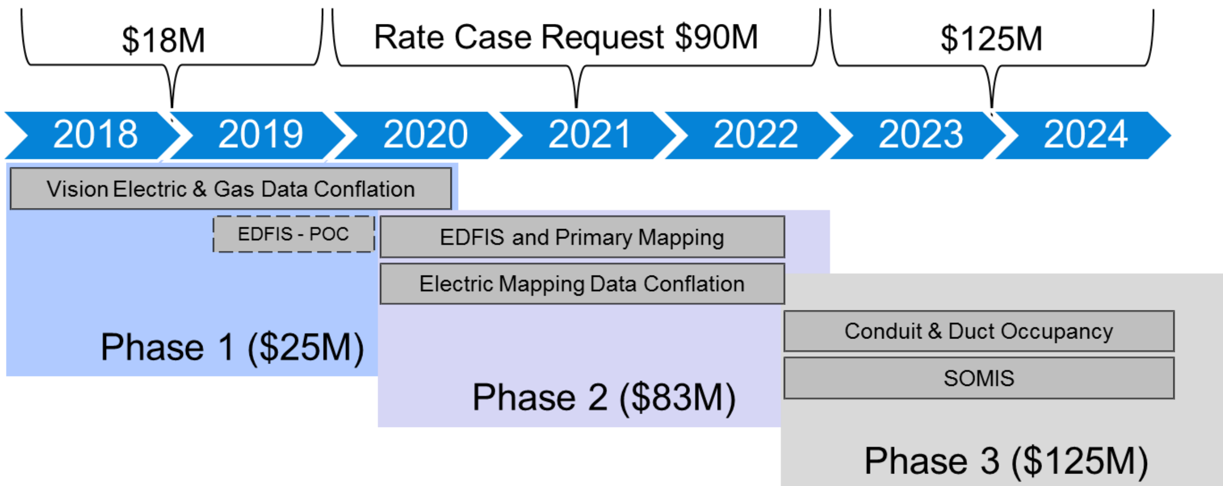
Phase 3 ($125 million), which is outside the horizon of the Company's 2019 rate filing, targets the Company's steam system and electrical conduits, including vacant and obstructed conduits. This phase involves converting the Company's Conduit and Duct Occupancy (C & D O) mapping system, which is essentially PDF images, to a modern GIS platform. At this time, Phase 3 is envisioned to be most complex technically and labor intensive of all the three phases. When Phase 3 is complete, GIS will enable the Company to display all mapping systems on a single platform.

Benefits of Phase 3 include:

- New mapping tools for conduit and composite maps

- Underground 3d Model to enable more visibility for electric and gas interference
- Integration of LiDAR data for road depressions
- Intelligent conduit mapping, enhanced load flow and feeder ratings
- Accurate property records for taxation and legal settlements

The graphic below shows the estimated timeline and associated cost for the various project milestones.



GIS PRODUCT OVERVIEW

The figure below illustrates the planned system architecture and application components for the Enterprise GIS.

GIS System Architecture

The Enterprise GIS system is based on a Services Oriented Architecture ("SOA"), which allows software applications to leverage a common set of services. Services can take many forms including:

- Geo-processing services (e.g. deriving coordinates for an address)
- File transformation services (e.g. PDF file creation of a map display)
- Application programming interface ("API") services
- Map display services (e.g. a map display service that provides an interactive map with electric features and the location of historical outage records)

Major components include:

- **Spatial Asset Management, Planning & Analysis tool** – The tool will be used primarily by mapping teams for maintaining Con Edison's facility models, updating maps, and publishing map services that can be used by the web and mobile users. The desktop GIS product is Schneider's ArcFM. The ArcFM product is an extension to Esri's ArcGIS Desktop product. The ArcFM extensions are functionality specific to electric and gas utilities. ArcFM will replace Con Edison's current mapping systems (VISION Electric, VISION Gas, Primary Mapping, EDFIS and Conduit Mapping).

- **Visualization tool** – All Company users will be able to access general map displays and specific application logic via a web browser. The map displays are maintained in the form of map services. Examples of map display services include a visualization that allows for the display and querying of primary electric features and conduit/duct locations. The web-based component will ultimately replace the multitude of visualization applications currently deployed including NetMap and Area Profile System. Map Centric data studies have demonstrated significant improvements in decision making using maps.

- **Field Mobility Mapping Tool** – The mobile applications will be based on Esri's ArcGIS Mobile platform and will replace the Byers application. This is expected to support over 3,000 mobile field users.

RISK MITIGATION

The following table summarizes major project risks and the associated mitigation plan.

Risk Item	Potential Impact to Project	Mitigation Strategy
Insufficient resources	- Schedule delays resulting from lack of timely response to vendor deliverables. - Functional gaps caused by lack of access to subject matter experts from stakeholder organizations/regions.	- Develop a comprehensive implementation plan with clearly define roles/responsibilities. - Proactively identify required resources and skillsets. - Work with stakeholder organizations in identifying prospective resources and associated time commitment.
Incomplete requirements	- Development "rework" because of lack of understanding of requirements. - Schedule delays. - Cost overruns.	- Phase 0 activities as defined in Section 3. - Allocating enough time and resources to sufficiently documenting and approving functional requirements. - Engaging requisite subject matter experts in requirements definition process.
Functional Scope Variance	- Schedule delays. - Cost overruns.	- Defining and adhering to a structured change control process that assesses change requests in terms value to business as well as schedule and cost considerations.
Change Management Plan	- Lack of organizational awareness of project - End user adoption of new systems.	- Incorporate change management into project implementation plan. - Initiate change management activities at an early stage of project. - Ensure change management specialists are part of implementation team. - Engage individuals from stakeholder organizations as project "champions".

System Testing	- Schedule delays.
	- Cost overruns.
	- System performance issues.
	- Loss of credibility of system/lack of system acceptance by end users.
		- Incorporate System Test Plan into the implementation plan.
		- Incorporate functional requirements into detailed test cases.
		- Identify system QA/QC manager who is responsible for overall definition and execution of test and acceptance plan.
		- Incorporate enough time in implementation plan for all types of testing including but not limited to:
		  ▪ Unit testing
		  ▪ System integration testing
		  ▪ Performance and scalability testing.

Project Interdependencies	- Schedule delays. - Cost overruns.	- Continuously identify parallel projects with interdependencies. - Define and execute an interdependency management communication plan. - Incorporate regularly scheduled interdependency meetings into the implementation plan.

Risk Item	Potential Impact to Project	Mitigation Strategy
Data Quality – lack of authoritative data or degradation in data quality because of legacy system data migration	- Schedule delays. - Cost overruns. - Loss of critical data	- Identify dedicated resources responsible for the overall data migration process. - Incorporate in the implementation plan the development of detailed data migration specifications. - Execute multiple pilot migrations to validate and refine data migration procedures and results. - Clearly define data acceptance criteria and the automated and manual methods for ensuring data deliverables adhere to the acceptance criteria.
Vendor Resources - insufficient vendor project resource commitment and/or unqualified vendor resources.	- Schedule delays - Unacceptable deliverables - Contentious client/vendor relationship	- Identify, review and approve vendor resources during Statement of Work definition. - Incorporate resource approval/removal language in contractual terms and conditions.
Adoption of New Systems	- Continued use of legacy systems, - Cost overruns.	- Define and implement effective change management plan. - Incorporate into the project implementation plan the development of a system training plan. - Engage representatives from the end user community in a “train the trainer” approach to increase the end user acceptance. - Implement “just in time” training.

DATA CONVERSION

Data conversion has been recognized as a high risk for cost/schedule overruns. There are three components of data conversion:

- Conversion: digitizing maps from paper or raster (picture)
- Migration: processing data from one digital source to another
- Conflation: adjusting graphic data and aligning to the real world

The data conversion tools have matured since Phase 0 in 2004 with the availability of Safe Software's product FME (Feature Manipulation Engine). Three market leading vendors have also emerged with proven conversion software products: Avineon, Cyient, and RAMTeCH. At this time benchmarking indicates that migration and conversion risk is more process and execution based than software-based. The following table is a summary of data conversion lessons learned and a high-level plan to mitigate data conversion risks.

#	Lesson Learned	Risk Mitigation
1	Data model is the most important component. Pare it down to the most important elements to ensure performance and flexibility.	• Developed and tested models for Electric and Gas in Phase 0.
2	Carefully evaluate vendor expertise, capacity and methodology.	• Established relationships with market leading data vendors. • Benchmark with peers and get references for qualified resources.
3	Data conversion specifications and acceptance must be complete and well documented.	• Head start on specifications and acceptance criteria. • Executed acceptance criteria during Phase 0. • Documented gaps. • Build a cross functional team structure with separate GIS solution & data migration teams.
4	Business SME involvement critical at all levels through the process to understand and validate data and map display.	• Project organization includes SME's from Engineering at all levels. • Involve resources as part of the data validation rules, not just part of the validation process.
5	Use data conversions tests to refine scope & requirements for full deployment.	• Define specific functional expectations, size and assumptions for a series of data conversion tests, rather than just "x" numbers of tests. • Use this in SOW for acceptance, advance to next phase, and payment criteria.
6	Test conversions "too big" had diminishing returns for the effort expended.	• Implement "right size" test conversions based on function, time box, expected functional results and number of resources

		that will be allocated to the QA/QC. • Augment with vendor resources to perform initial visual and automated testing. Use Company resources as final acceptance for critical data such as Feeder Maps.
7	Automate QA/QC	• Head start on specifications for automated QA/QC. Evaluated vendor tools from Esri and RAMTeCH that can be leveraged. Documented gaps for targeted tools that can be developed.
8	Data Errors	• Start change management process early. Recognize that annotation will be a concern. Maps will look different. • Processes to review "map data" will change. Focus on accomplishing business needs, not maintaining legacy formats.
9	Manage risk and single-point of failure with data conversion process.	• Use two data conversion vendors to execute multiple data migration iterations, cross-checking, backlog processing and provide contingency.

COST BREAKDOWN

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	$3,000	$3,000	$3,000	$3,000		**$2,700**

Future Capital Elements of Expense

EOE	Request 2020	Request 2021	Request 2022	Request 2023	Request 2024
Labor	$3,034	$3,030	$3,000	$6,000	$6,000
M&S	-	-	-	-	-
A/P	$20,482	$20,652	$20,479	$43,354	$43,354
Other	$1,819	$1,834	$1,890	$3,850	$3,850
Overheads	$4,666	$4,483	$4,703	$9,298	$9,298
Total	**$30,000**	**$29,999**	**$30,001**	**$62,502**	**$62,502**

As the project transitions from development to production of the various mapping systems new Operations and Maintenance ("O&M") costs will be incurred. We anticipate that additional costs will be partly offset by the retirement of the various legacy systems. At this time, there is no incremental O&M request included. O&M costs will be re-evaluated as the project implementation is completed.

Annual O&M Funding Levels ($000):

EOE	Budget 2021	Request 2022	Request 2023	Request 2024	Request 2025+
Vision	$1,000	$1,000	$1,000	$1,000	-
EDFIS	-	$500	$500	$500	-
Primary	-	-	$1,000	$1,000	-
C&DO	-	-	-	-	-
Enterprise GIS	-	-	-	-	$5,000
Total	**$1,000**	**$1,500**	**$2,500**	**$2,500**	**$5,000**

APPENDIX A – GIS GRID ENABLERS

GIS Enabler Description	Operational Efficiency	Cost Avoidance	Collaboration	Customer Experience	Employee Engagement	Stakeholder Engagement	Compliance
Providing capability of intelligent modelling of conduit duct network and duct occupancy. The current record of Con Edison's conduit network is "unintelligent" or static maps that cannot be effectively incorporated into design layouts, electric of gas maps etc.	✓	✓	✓		✓		✓
Adoption of standard coordinate systems and accurate positioning of facilities in map displays. The current systems have inaccurate, proprietary and inconsistent coordinates for facilities.	✓	✓	✓	✓	✓	✓	✓
Comprehensive data validation prior to posting facility record updates to corporate repository - higher data quality	✓		✓		✓		✓
Consolidation of four electric mapping systems into single system	✓	✓	✓		✓	✓	✓
Consolidation of CuFlink into GIS electric model and improved customer facility matching.	✓			✓	✓		
Consolidation of electric and gas mapping systems into single system	✓		✓		✓		✓
Ability to maintain a single comprehensive model of the entire electric distribution system (primary, secondary service customers)	✓	✓			✓		✓
Consolidation of multiple visualization systems e.g. NetDVD into enterprise GIS environment	✓	✓	✓		✓		✓
Ability to display electric, gas and steam facilities into a single map display	✓		✓		✓	✓	
Utilizing New York City and Westchester county base map features e.g. road edge, street center line…	✓		✓		✓	✓	
Programmatic synchronization of electric asset data between GIS and WMS	✓		✓		✓		✓
Providing a comprehensive electric model to external analysis and operational systems e.g. PVL and STAR from single system.	✓		✓		✓		✓
Consolidation of CuFlink Gas into GIS model and improved customer facility linkage.	✓	✓			✓		✓
Improve self-service capabilities for end users to create ad-hoc map products	✓		✓	✓	✓	✓	✓
Ability to integrate external data e.g. Flood plains into map displays using web services	✓		✓		✓		✓
Capability to consolidate non-enterprise GIS systems into enterprise GIS	✓				✓		
Ability to create all standard electric map products from a single system of record	✓				✓		
Providing enhanced gas model to external analysis and operational systems (e.g. SynerGEE and MRP)	✓						
Ability for end users to perform ad-hoc queries against GIS data and extract to multiple file formats	✓		✓		✓		✓
Ability to incorporate new features into GIS model without custom coding.	✓						
Programmatic synchronization of valve data between GIS and Gas Inspection System	✓				✓		✓
Ability for field users to connect to and display up to date spatial asset data.	✓				✓		

X	Capital
	O&M

2020 – Capital – Electric Operation

Project/Program Title	Non-Network Resiliency with FLISR
Project Manager	Kevin Oehlmann
Hyperion Project Number	PR.23288073, PR.23339097, PR.23291837
Status of Project	Engineering/Planning
Estimated Start Date	1/1/2020
Estimated Completion Date	12/31/2023
Work Plan Category	Operationally Required

Work Description:
Con Edison's Non-Network System is comprised of 4 kV primary grids and 4/13/27 kV autoloops. On Staten Island, the Non-Network System also includes Fox Hills and Fresh Kills 33 kV load areas. Autoloops are looped circuits that are fed power from both ends, and which may have small spurs off the main line to distribute power throughout a neighborhood. A typical Con Edison circuit runs for several miles. A failure at a certain point of the circuit will affect other customers on the same circuit to the location of the closest upstream protective device. In some cases, damage or faults on spurs can flow up to the main feeder line, potentially causing outages for many more customers.

Con Edison has progressively developed Fault Location, Isolation, and Service Restoration ("FLISR") capabilities on the Non-Network portion of its distribution system through the deployment of protective devices like reclosers and sectionalizing switches. These devices allow the Company to locate permanent faults, isolate the damaged conductors and/or equipment, and restore service to undamaged portions of the affected circuit(s).

This program will replace older equipment with new technology that will further enhance FLISR capabilities. For instance, traditional pad mounted primary selective switches or automatic transfer switches ("ATS") installed at Con Edison are live front, live open bus design without supervisory control and data acquisition ("SCADA") capability. Today, ATS gear is available that is dead-front (where all connections are insulated and totally shielded, and shields are visually connected to ground), enclosed bus, with SCADA capability, and with equipment ratings that meet or exceed the legacy gear. The SCADA capability of the newer gear provides greater visibility and remote control of the switch, and the dead front and enclosed bus design requires less maintenance and is less prone to outages caused by animal infestation.

Work completed via this program will expand these capabilities through deployment of Smart Switches – i.e., devices with SCADA capability and/or the ability to operate automatically without operator intervention. Smart Switches are a key component of a FLISR capability. Types of Smart Switches contemplated as part of this program include reclosers, SCADA gang switches, and ATS, PulseClosers/Intellirupters, and SCADAMate switches.

These switches will enable the following automated control schemes:

- Automatic transfer of customer load from the normal source to an alternate source. Automatic control schemes are deployed using pad mounted switch gear as well as pole mounted reclosers.
- Looped feeders are reconfigured via an automated sequence of operations that commences after the fault. This results in a reconfiguration where two automated switches closest to the damaged portion of the loop open, and normally open automated switches close, to restore all customers not in the faulted portion of the loop.
- Radial spurs fed off the main run of an auto-loop are reconfigured to develop “spur loops.” In this design two spurs are supplied from two different segments of an autoloop to an automatic normally open tie switch. When a portion of the main run of the loop is de-energized as described above, the spur loop re-configures via automatic switching such that the portion of the spur loop connected to de-energized, faulted segment of the main run is fed from the non-faulted segment of the loop. This allows the customers on the spur connected to the faulted segment of the main run to remain in service in cases where they would have been de-energized due to the fault.
- Additional branch protection may be added in series with existing branch protection by using technology to achieve greater coordination of the series devices. This will reduce the number of customers affected by faults at the end of a radial spur line.
- New FLISR schemes will allow the addition of automatic switching devices to 4 kV grid feeders. The additional devices reduce the number of customers on each feeder segment and thus reduce the number of customers impacted by a fault on a line.

Justification Summary:
The Non-Network Resiliency FLISR program will expand Con Edison’s reliability and resiliency in two ways, (1) through greater visibility and automated control, and (2) limiting the impact of customer outages.

By installing additional smart switches, the Company will increase the number of automatic protective devices per circuit and further segment its circuits. This reduces the number of customers that are impacted as a result of a single point of damage on the system, which in turn improves SAIFI metrics.

The installation of additional smart switches with SCADA communications will facilitate quicker restoration of outages by more quickly identifying the fault, automatically operating, and updating the operator on the state of the system. In addition to the benefit of automatic operation, having additional controllable devices also allows greater flexibility for restoration when a failure occurs.

Supplemental Information:

- Alternatives:
  Manual switches can be installed in lieu of Smart Switches and Automatic Transfer Switches. Manual switches require a crew to be dispatched to the appropriate location in order to operate them. This does not support the overall Grid Innovation goals of reliability, resiliency, and flexibility, and it would also result in an increase in the outage duration.

- Risk of No Action:
  With no action non-network customer outages will not be reduced. Risk of cascading outages that result in the loss of a 4 kV grid will not be reduced.

- Non-financial Benefits:
  With the decrease in, or mitigated results of, power outages, customer experience will be enhanced.

- Summary of Financial Benefits (if applicable) and Costs:
  Although difficult to quantify, the benefits of this program include enhanced reliability and resiliency of the system during both blue-sky days and major storm events.

- Technical Evaluation/Analysis:
  Each project will be evaluated in terms of improvement to the indices of importance for the system. All projects will be evaluated in terms of SAIFI/CAIDI improvement.

- Project Relationships (if applicable):

- Basis for Estimate:
  Historical unit costs.

Annual Funding Levels ($000)

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	305	292	274	278
M&S	-	343	393	429	424
A/P	-	568	580	567	570
Other	-	256	248	231	231
Overheads	-	161	149	133	134
Total	**-**	**2,100**	**2,100**	**2,100**	**2,100**

X	Capital
	O&M

2020 – Electric Operations/System and Program Engineering

Project/Program Title	Smart Sensors
Project Manager	Stan Lewis
Hyperion Project Number	PR.23288078 / PR.23317267 / PR.23291814
Status of Project	Engineering/Planning
Estimated Start Date	1/1/2020
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
Recent advances in sensing and communications technologies provide utility operators and planner's unprecedented visibility and information about system assets. Examples of these advances include the successful use of the structure observation systems ("SOS") to mitigate underground electrical failures in response to challenges with Metropolitan Transit Authority ("MTA") facilities in 2017[13], or pressure, temperature and oil level sensors installed on underground network transformers which have played a key role in reducing transformer failures. Another example is by using advanced communications technology we operate NWPs (network protectors) remotely enhancing feeder processing and storm preparation.
To maximize the value of this technology and increase visibility at the grid edge, Con Edison plans to deploy several different sensors as part of the grid innovation effort for the distribution system. Specifically, Con Edison will (1) deploy additional structure observation systems that use visible and infrared imaging and gas sensors, (2) embed smart sensors into cable equipment like secondary crabs and primary splices, and (3) add pressure sensors to network protectors that will monitor the nitrogen used to keep the equipment dry.

Structure Observation System
The SOS is both an integrated environmental monitoring solution as well as a platform for integrating other equipment sensor data, such as the smart crabs, smart primary splices, and network protector pressure sensors. As an environmental monitor, the SOS may collect data regarding combustible gas, temperature, visible and infrared images and other parameters. The SOS will transmit the environmental sensor data it collects, in addition to information from smart equipment sensors, over a secure wireless network (cellular or Advanced Metering Infrastructure ("AMI") network). The data

[13] Several underground electrical failures were mitigated in early stages of a pilot of the SOS system to meet the regulatory compliance of New York Public Service Commission quoted below in Case 17-E-0428, In the Matter of an Investigation into the April 21, 2017 Metropolitan Transportation Authority Subway Power Outage and Consolidated Edison Company of New York, Inc.'s Restoration Efforts, Order Directing Steps to Safeguard and Maintain Adequate Utility Service to the Subway System (issued November 10, 2017), pp. 13. The successful deployment and operation of the SOS devices in this application demonstrates suitability for a system-wide implementation.

"Con Edison will install by September 30, 2017, sensors and monitoring equipment capable of detecting carbon monoxide, water level, and arcing in all the Con Edison manholes that provide a direct connection to the 462 MTA passenger/signaling facilities except in a very limited number of conditions where unusual water or other conditions would make the use of the sensors and monitoring equipment infeasible."

will be securely received, processed, and analyzed through an Enterprise Data Analytics Platform ("EDAP") for several uses:

- Immediate for operational use for imminent equipment failures
- Short term for inspection, repair, and program optimization
- Long term for optimized capital planning

The combination of the environmental sensing and data transmission functionalities presents an opportunity to transform the way the Company monitors its assets and maintains situational awareness. In lieu of a single data point collected every eight years through an inspection cycle the Company will have a history of data through the SOS as well as on-demand visibility. This increased visibility and functionality can reduce ongoing costs, by supplementing, and ultimately replacing, targeted inspections.

Currently, the detection and mitigation of underground electrical abnormalities is mandated by New York Public Service Law §65(15) Case 04-M-0159. The Order is currently fulfilled through a manual inspection process. The primary goal of this capital expenditure is to improve detection capabilities, periodicity of detection and program efficiency and effectiveness by directing more resources to proactive work. A partial or full transition of the inspection program to a virtual approach, relying on SOS, would occur after establishing performance as equivalent if not improved over the current manual process and include notification to regulators.

Smart Sensors in Cable Equipment

Smart secondary crabs and primary splices will collect electrical parameters and send this data to an SOS.

Specifically, the smart secondary crab will measure current from each connected pocket of a secondary crab. These measurements will be analyzed for maximum and average loading to support planning decisions of cable and crab replacement and reinforcement. The smart secondary crab will also capture significant short-term changes to indicate whether an immediate response may be required. This is possible by observing when appreciable current drops to zero, indicating a limiter has blown open.

Primary distribution cable splices with embedded sensors will provide the Company with more information on the primary network and condition of primary cable and splices. The sensors will improve employee/public safety, provide data to monitor the health of network primary assets, and improve feeder restoration. The sensors may include status of feeder (energized/de-energized), voltage, current, phase angle, temperature, and presence of partial discharge. Partial discharge monitoring will provide information on the condition of both the splices and the cable it is joining. The information collected from these sensors will be used in stages. Initially, the information will be obtained through a contact device used by crews to provide the immediate status of the splice and cable. Future development will integrate with the SOS platform to remotely monitor the cable and splices. The smart splices will use a cold shrink technology which has proven to be the most reliable on our network system.

Network Protector Pressure Sensor

The Company is nearing the completion of the deployment of pressure, temperature, and oil ("PTO" sensors) on all underground transformers. Leveraging the success of the pressure sensor on transformers, this project will add the same pressure sensors to submersible network protector ("NWP") housings. These housings are also sealed from the elements and pressurized. The pressure sensor would help to determine if there is a leak or fault in the NWP housing. The NWP pressure sensors require a communication channel to backhaul the asset data. Pressure sensors would initially be connected on locations with existing SCADA communications until the ability of the AMI network to reach NWPs is tested and deployed.

The planned annual equipment deployed in this program includes:

Equipment	Approximate # of units
Structure observation system	1,500
Smart secondary crabs	1,070
Smart primary splices	250
network protector housing pressure sensor	300

The installation of SOS monitoring devices, smart secondary crabs, and smart primary splices may occur with routine and targeted work selected for safety and reliability. Targeted locations may include statistical safety for manhole events and energized objects as well as for reliability such as structures with multiple feeders.

Justification Summary:
One of the defining features of the Grid Innovation program is using sensing technology to provide greater situational awareness of the electric system, and then using data analytics and advanced management systems to more effectively plan and operate the system. This acceleration of sensing technologies, currently deployed on a targeted reliability-focused basis, will develop the above capabilities more quickly. The deployment of these sensors offers public safety benefits, operational efficiencies, and potential cost savings. Each sensor serves a specific purpose with specific benefits, described below:

Structure Observation System
As demonstrated successfully in its pilots, the SOS provides safety and reliability benefits. In effect, the SOS replaces all the essential components of a physical inspection without anyone entering the structure. The model for inspections is transformed from physical to virtual. Significantly, the periodicity of the virtual inspection is multiple orders of magnitude higher than the physical inspection, the SOS is monitoring continually as compared to singularly in a 5 year or 8 year manual inspection cycle. This combination of electrical and environmental monitoring will provide operators, engineers, and planners with unprecedented insight into system performance and how they manage it, resulting in greater safety and reliability.

In addition to the improvements in public and employee safety, the increased grid edge visibility, to the extent that it can remotely perform structure inspections, will provide cost savings. Once remote monitoring is fully deployed over a twenty year period, the Company expects the majority of its structure inspections to be done virtually with no contractor support.

The ability to rapidly respond to an underground electrical cable failure will potentially reduce collateral property damage, evacuations from carbon monoxide, and injury. In an average year, there are over 2,000 manhole events. While a majority of cable failures are singular and isolated, some failures develop into fires and explosions. The reduction of a fraction of these escalated events could lead to significant cost savings by alerting operators to manhole event precursors and addressing them before they progress to more dangerous and damaging situations. Through earlier warnings, collateral damage is reduced.

Smart Sensors in Cable Equipment

Smart secondary crabs provide sensing of the condition of secondary crab joints, where there is currently no visibility. This visibility offers both short-term operational benefits and long-term planning benefits. Without the smart secondary crab, the Company may be unaware of blown limiters until a more serious equipment failure manifests. Through earlier detection of failing secondary cable connections, the Company is able to address operational issues before they become significant enough to result in customer outages. On a longer time horizon, the Company is able to take readings of loading and status to inform planning decisions to optimize long term capital spend.

The smart primary splice offers similar benefits on the primary portion of the distribution system. In the short term, crews on site can take measurements to determine cable status and loading conditions, offering another measurement point for safely conducting field work. As remote monitoring is enabled over 5-10 years, the operational and planning benefits of smart primary splices include avoiding feeder faults and loss of system reliability.

Network Protector Pressure Sensor
With visibility to detect leaks or pressure loss in the network protector housing, the Company will have an earlier indication of moisture intrusion which can compromise the performance of the switch, keeping it from operating when required and reducing grid performance. A pressure spike could indicate a fault in the NWP housing and crews could then respond more quickly to high priority repairs, improving reliability and yielding public safety benefits.

Supplemental Information:

- Alternatives:
  The alternatives to the accelerated deployment of these advanced sensors include a phased deployment based on the existing reliability program or taking no action and continuing to rely on the Company's time-based inspection program (see below).

  Structure Observation Systems are currently being deployed through an existing risk reduction program. The additional deployment of structure observation systems through this program nearly doubles the pace of implementation, which in turn reduces the time needed to transition from the timed based process to a condition-based inspection model.

  The current process of inspections, whereby a person enters a structure once every eight years, can continue at the same rate but with an enhancement. A technical alternative to full SOS deployment would be a through-cover camera inspection platform to augment the current manual inspections that would allow an operator to inspect a structure from street level. One benefit of through cover inspection is the immediate location targeting and focused image and infrared data to identify potential cable failures; the downside is the information is intermittent and still requires significant administrative overhead and expenditure to manually inspect structures. Therefore, deploying this existing SOS technology immediately is the optimal path.

- Risk of No Action:
  By not taking the opportunity to deploy additional monitoring equipment, the Company will have to continue to rely on programmatic, time-based inspection programs to assess structures. The value fluctuates year over year, but approximately 80% of the time, these inspections result in no action taken. In the long run, this is not cost effective, as it requires the use of contract resources to inspect structures and report back. This approach foregoes the efficiency benefits associated with remote monitoring for structures and equipment, quantified below.

- Non-financial Benefits:
  The primary non-financial benefit of this program is an increase in public and employee safety. Additionally, this program will contribute to a reduction in emergency response time, particularly during peak event periods (such as storms), since fewer emergency events as a result of degraded equipment will occur. It will also contribute to a reduction in troubleshooting time since defective equipment will be replaced before creating an energized object, which can be time consuming to diagnose. Customer experience will be improved by the increased reliability.

  The ultimate reduction and elimination of the underground inspections will have an overall benefit to the safety and reliability for customers and employees, and tangentially quality of life advantages. Manual inspections involve the disruption of traffic and pedestrian patterns, whereas the SOS devices will be transparent to the public.

  Summary of Financial Benefits (if applicable) and Costs:
  Smart sensors offer financial benefits by reducing the reliance on contractors for manual inspections and reducing the amount of damaging manhole events. On an annual basis, as SOS devices are deployed, they begin to immediately offset the cost of contractor inspections. The average annual contractor inspection budget is $7M for an eight-year cycle of inspections. When SOS devices are fully deployed over a twenty year period, the Company projects no need for contractor expenditure for manual inspection. The benefits of the SOS also accrue linearly as the sensors are deployed, meaning the contractor inspection budget is offset annually by the proportion of sensors deployed. Smart sensors also produce benefits by reducing the collateral damage associated with the low-probability but high-impact manhole events that escalate to fire or explosions. Conservative estimates for the damage associated with all events are $2M per year, and the benefits associated with avoiding these events would scale linearly with the deployment of the SOS.

  The cost estimates used for this analysis conservatively use 2018 costs for long-term projections. The Company anticipates the cost of technology may decrease over time as more vendors develop the associated technologies, and the deployment rate of the sensors could then be accelerated. In contrast, there is a high probability that manual inspection costs, including both the unit cost and the procurement and oversight required will continue to increase. The avoidance of collateral damage to public property and personal injury is difficult to quantify yet can't be overstated.

- Technical Evaluation/Analysis:
  The generation of combustible gasses, such as CO, from the burning of insulation in Company assets has been well established. The detection of these gasses can be accomplished through electrochemical and infrared based gas detectors. Likewise, voltage present on an energized object can also be measured regularly for abnormal conditions. What has changed substantially is the wireless infrastructure through which data can be sent. Current wireless technologies can be deployed cheaply, at low power, and high bandwidth. As data is retrieved on a more frequent basis from sensors embedded in cable splices, the Company will be able to make longer term capital replacement decisions based on historical stresses and asset condition.

- Project Relationships (if applicable):
  This project is dependent on the AMI communications infrastructure or a suitable wireless alternative and the data analytics platform to most effectively utilize the data generated. The

proliferation of sensing technology will also bring more data back to operators. A future Advanced Distribution Management System ("ADMS") would receive the data inputs and translate those for operator decision support, particularly Regional Engineering and Control Centers.

- Basis for Estimate:
  The basis for this estimate is unit costs for the equipment and historical labor rates for installation based on the experience of the SOS installations in 2017 and 2018.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Request 2019	Budget 2020	Budget 2021	Budget 2022	Budget 2023
Labor	-	634	535	547	844
M&S	-	999	1,261	1,229	3,423
A/P	-	2,114	2,161	2,119	2,043
Other	-	618	558	548	859
Overheads	-	1,935	1,787	1,857	2,931
Total	**-**	**6,300**	**6,301**	**6,300**	**10,100**

X	Capital
	O&M

2020 – Electric Operations/ System Design

Project/Program Title	Underground Network Resiliency
Project Manager	Leeman Hong
Project Number	PR.23291821
Status of Project	Initiation
Estimated Start Date	1/1/2020
Estimated Completion Date	12/31/2030
Work Plan Category	Strategic

Work Description:

This program will install intelligent, communicating underground interrupters to improve the resiliency of the underground network distribution system. This new technology delivers automated fault interrupting capability that is not available on the manual isolation switches currently installed and, in series with an isolation switch, can provide a visible break. These interrupters also provide remote grounding to clear for a backfeed condition (reverse power flow) on the primary feeder. The interrupters will be installed on primary feeders at two types of locations, existing switch locations in wholly underground networks, or in new locations to automatically segment the network and non-network primary feeders.

The Con Edison system consists of 2,206 primary distribution feeders, which are designed to have the substation feeder breaker open anytime a fault occurs. When a feeder breaker opens, the load shifts from the primary to the secondary network, which provides continuous service to customers can stress the secondary network components until the primary distribution feeder is restored.

To date, Con Edison has installed over 300 isolation switches on primary distribution feeders across the underground system. These switches allow Con Edison to manually reconfigure and isolate a fault, after the station breaker trips open. If the fault was on the load side of the switch these switches allow us to partially restore the primary distribution feeder by manually reconfiguring the system and dispatching a field crew.

Due to the size of Con Edison's system, primary distribution feeder faults are relatively common, occurring at a rate of approximately three per day over the last ten years. Expeditiously restoring primary distribution feeders is critical to resolving contingency situations, particularly in the peak summer months.

In 2016, Con Edison worked with a manufacturer to develop an underground interrupter which will sense a fault on the load side and automatically operate before the substation breaker. The automated sensing and reconfiguration functionality will improve the reliability of the primary system and secondary system by keeping a portion of the primary feeder in service, thus reducing the stress on the secondary network and mitigating the portion of the network in a contingency. In turn, this increases the resiliency of the underground network.

The implementation plan is to deploy these underground interrupters on a targeted basis of approximately 500 units starting with areas of the grid that can be made more reliable with the least expense. Locations will be chosen based on the system design (network and non-network primary feeders), reliability performance, and cost to implement. Generally, it is more cost effective to install the communicating underground interrupters where there is an existing structure for a manual isolation switch. The plan calls for the installation of approximately 16 interrupter installations per year, the interrupter will be installed in a new or an existing structures.

Justification Summary:
By proactively addressing these trends, Con Edison can deliver significant benefits to its customers through this program by continuing to deliver reliable, resilient, safe, and affordable service while meeting consumer's evolving energy needs. Specifically, this supports the reliability, resiliency, and operational flexibility goals of the Grid Innovation program through the following two high-level objectives associated with the underground network resiliency program:

1. Enhance reliability in the secondary by improving performance on the primary feeders
2. Auto-isolate faults network primary feeders supplying overhead non-network primary feeders.

Enhance reliability in the secondary by improving performance in the primary feeders
By systematically installing the auto isolating underground interrupters (either through upgrading all existing mid feeder switches or installing them where no switch currently exists), Con Edison will improve the reliability in the secondary portion of the network system. This will be accomplished by automatically sensing, reconfiguring, and restoring portions of the primary feeder after a primary fault. This maximizes the number of network transformers that remain in service. The interrupter provides a system design concept that relies on self-healing eliminating the time spent traditionally to reconfigure and restore equipment to service.

Auto isolate faults in the exposed portions of network primary feeders
For network feeders supplying overhead non-network feeders, faults that occur on the non-network feeder impact the entire network that is served by the associated network feeder. By deploying an underground interrupter where the underground cable transitions into aerial cable, during an overhead event, the damaged overhead sections of the non-network feeder would be disconnected from the network primary feeder. This will avoid a network primary feeder contingency, consequently avoiding a contingency on the secondary network, mitigating the impact of the outage.

Supplemental Information:

- Alternatives: The alternative is to continue to deploy the underground sectionalizing switches and not take advantage of the functionality and self-healing offered by the new interrupter switch.

- Risk of No Action: By not acting on this program, the system design would continue to rely on the secondary network components to carry the load when a primary feeder faults. Over the long term, this will lead to greater overall failure rates and greater capital spending.

- Non-financial Benefits: The non-financial benefits of this project include greater reliability, greater customer satisfaction, and improved safety. The improved reliability derives from adding self-healing functionality to the primary system, reducing loading on transformers and secondary cable, and reduced burnout rate of the secondary. The reliability improvements and reduced portion of the network that is in contingency will result in fewer customer outages and greater customer satisfaction. Safety improvements are based on a net reduction in safety risk from secondary and transformer incidents.

- Summary of Financial Benefits (if applicable) and Costs: The costs associated with this project include the equipment costs of the interrupter and SCADA box, the installation cost, and the cost of a new structure (if applicable). These costs will vary per installation but are expected to cost approximately $250,000 each.

- Technical Evaluation/Analysis: As part of developing and vetting this technology, Con Edison initiated the development of the interrupter as a R&D project. A study was performed that replaced all underground sectionalizing switches in a network and calculating the reliability improvement to the network, as measured through the Network Reliability Index ("NRI"). The results of that study showed an improvement of approximately 10 percent.

- Project Relationships (if applicable): To enable the operational flexibility to shift load, the communicating network protector relays for each transformer on the feeder are required. These are being deployed as part of the Distributed System Platform ("DSP").

- Basis for Estimate: The method used to determine the cost estimate was based on historical construction costs to install a similar underground sectionalizing switch and vendor equipment pricing for the newly developed interrupter. In 2023, it is anticipated that the installation of interrupters will require the construction of new manholes.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	2	2	1	5
M&S	-	833	856	840	3,179
A/P	-	1,669	1,714	1,683	6,387
Other	-	218	223	219	830
Overheads	-	1,278	1,205	1,256	4,619
Total	-	**4,000**	**4,000**	**4,000**	**15,000**

Exhibit__(EIOP-4)

New Business and System Expansion

Schedule 1: T&D New Business and System Expansion Capital Program and Project Summary

Electric T&D *New Business & System Expansion*		Year Total Current Budget Total Dollars ($000)			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
NEW BUSINESS					
Organization	**White Paper**				
Distribution	Meter Installations	24,306	24,306	24,306	72,918
Distribution	New Business Capital	165,000	165,000	168,000	498,000
	New Business Subtotal	**189,306**	**189,306**	**192,306**	**570,918**
SYSTEM EXPANSION					
Organization	**White Paper**				
Distribution	Cable Crossing (XW Riverdale & BQ Flushing)	5,000	2,656	1,014	8,670
Substations	E179th St - Switchgear and Bus Replacement	12,200	10,357	22,211	44,768
Substations	Hudson Avenue Distribution Switch Station	34,240	68,480	69,480	172,200
Distribution	Load Transfer Newtown to N. Queens	24,000	1,800	-	25,800
Distribution	Load Transfer W42nd St to Astor	1,500	4,000	8,000	13,500
Distribution	Network Transformer Relief	12,382	12,382	12,382	37,146
Distribution	Nevins Street Battery Storage and Electric Vehicle Charging	5,000	5,000	-	10,000
Distribution	NonNetwork Fdr Relief (Open Wire)	7,283	7,283	7,283	21,849
Distribution	Overhead Transformer Relief	2,299	2,299	2,299	6,897
Distribution	Primary Feeder Relief	10,844	10,844	10,444	32,132
Distribution	Queensboro Bridge Riser Replacement	1,600	10,600	5,500	17,700
Distribution	Secondary Main Loads Relief	2,529	7,064	7,064	16,657
Distribution	Yorkville Crossings and Feeder Relief	8,500	7,724	7,724	23,948
	System Expansion Subtotal	**127,377**	**150,489**	**153,401**	**431,267**
TOTAL ELECTRIC					
	New Business	**189,306**	**189,306**	**192,306**	**570,918**
	System Expansion	**127,377**	**150,489**	**153,401**	**431,267**
	Total New Business & System Expansion	**316,683**	**339,795**	**345,707**	**1,002,185**

Infrastructure Investment Panel				
O&M Program Changes				
EIOP - System Expansion				
($000)				
		RY1 Program Change	**RY2 Program Change**	**RY3 Program Change**
System Expansion				
Organization	**Program Change**			
Transmission	138 and 345kv Shunt Reactor Priority Study	200	(200)	-
Transmission	Specializied Transmission Planning Studies	100	-	-
Substations	Cricket Valley Substation	400	-	-
TOTAL ELECTRIC				
	Grand Total	**700**	**(200)**	**-**

Schedule 2: T&D New Business and System Expansion O&M Program Change Summary

Schedule 3:

T&D Capital White Papers New Business

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Meter Installations
Project Manager	Charles Feldman
Hyperion Project Number	PR.2ED0771, PR.2ED1211, PR.2ED4171, PR.2ED5171, PR.2ED9171, PR.9ED3031
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program provides for the installation of electric revenue meters and associated metering equipment for revenue collection as required by PSC regulations. The installation is to be handled by Electric Operations personnel and include electric meters and revenue grade instrument transformers. Meters are to be installed in new customer locations, in existing customer locations that were upgraded, and as replacements for mechanical meters which require more frequent testing.

Units per Year: Approximately 79,000 units that include electric meters and/or auxiliary metering appurtenances.

Mandatory: Approved electric revenue metering equipment as required in PSC No. 10 – Electricity, General Rule 6 and 16 NYCRR Part 92.

High-level schedule: This is an ongoing activity where the metering equipment is purchased based on customer requests and operational needs.

The replacement of failed meters and new business work will be done by Electric Operations and is not covered in the AMI project. The meters installed will be the same as those installed by the AMI project.

Justification:
Meter Installation is necessary to provide service to customers. Electric meters are required by the New York State PSC for revenue collection.

Supplemental Information:

- Alternatives:
  There are no acceptable alternatives to the use of PSC approved metering devices as specified in PSC 16 NYCRR Part 92 and PSC No. 10 – Electricity for electric rate paying customers. Meters provide the means to accurately record customer demand, implement time of day rates, demand response and energy efficiency programs and comply with regulatory metering programs such as reactive power. The last step in energizing new customers with electric service is to install the meter.

- Risk of No Action:

Without meters, new tariffs would have to be developed for flat rate billing which are not approved by the PSC at this time. In addition, service for many new customers would be delayed or recognized as unmetered.

- Non-financial Benefits:
  Metering a customer's energy usage provides an objective measure of the amount of energy used. This improves customer satisfaction by removing any doubt a customer might have about the accuracy of their bill. Electric meter data for customers is used to invoice customers for usage and will improve system planning for critical system upgrade engineering analysis.

- Summary of Financial Benefits (if applicable) and Costs:
  Installation of electric meters provides an accurate means to record customer energy usage for revenue collection. In addition, meters provide a point of disconnection in the event of non-payment. Each year, the Revenue Protection Unit team uncovers approximately 3,000 cases of theft and irregular meter conditions.

- Technical Evaluation/Analysis:
  Meters, Devices and Instrument Transformers are selected based on customer loads, engineering analysis of manufacturer's equipment relative to our service territory as well as previous performance of similar products. Included in the budget are add-ons to support time-of-use and interval data as well as remote communications.

- Project Relationships:
  The Meter Installation program is directly tied to the Meter Purchase program. Con Edison needs to properly purchase and install new meters to bill customers and operate a safe and reliable network.

- Basis for Estimate:
  Historical unit cost

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	11,510	13,214	13,933	15,799		15,354
M&S	408	435	551	729		557
A/P	352	389	348	329		208
Other	(127)	(265)	(292)	(271)		-
Overheads	10,272	13,141	10,690	9,677		8,173
Total	**22,415**	**26,914**	**25,230**	**26,263**		**24,292**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	9,523	10,149	10,414	10,483	10,559
M&S	2,120	2,127	2,103	2,046	1,988
A/P	203	202	199	189	182
Other	3,525	3,603	3,611	3,481	3,400
Overheads	8,733	8,223	7,976	8,106	8,175
Total	**24,163**	**24,306**	**24,306**	**24,306**	**24,306**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	New Business Capital
Project Manager	Darren Scarimbolo
Hyperion Project Number	Various
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
Based on the required company facilities necessary to complete service installations for new business, the electric new business capital work is broken into two categories: Retail and Major Projects.

Under $100k Retail: To adequately supply proposed new customer loads, the Company must install or replace an existing overhead or underground service. For underground services, the Company installs or replaces an underground service cable in an existing service conduit or new service duct. For an overhead service, the Company extends a new service or replaces an existing service from our facilities to the customer's point of attachment.

Over $100K Projects Major Projects: To adequately supply proposed new customer loads, the Company must install service cable, primary and/or secondary cable in vacant conduit or newly installed conduit, or additional overhead (OH) primary/secondary spans/poles. Installation of transformers and manholes are required while manhole and service box enlargements may also be required.

Justification Summary:
Over the next five years we expect the trend for larger projects to increase steadily, similar to the trend we see for smaller-scale developments and individual residential endeavors. We have experienced an upswing in the smaller projects particular in our Brooklyn/Queens service territory.

In the current 5-year time frame, business entities remain engaged in building various projects; some of which include:

Manhattan
The Hudson Rail Yards platform is scheduled to be completed in 2019. The Hudson Yards development zone encompasses the corridor west of Madison Square Garden and around the Hudson Yards and north towards West 42nd Street along the new Hudson Blvd. The Eastern Rail Yards will be adding 65 MVA of primarily commercial loads. The Western Rail Yard platform is anticipated to begin construction this year and will be primarily for residential loads. Additionally, there are various developments planned across the district including Brookfield's Manhattan West, 3 Hudson Blvd., 50 Hudson Blvd, and 66 Hudson Blvd, which all vary from mix-use commercial/residential buildings with trade floors that will add an additional 88 MVA with service dates varying from 2019 to 2021.

Upper Manhattan is seeing large increases in load in areas like Washington, Morningside, and Hamilton Heights where small businesses are developing into large offices spaces to keep pace with the gentrification of the areas and contributing to the luxury residential growth. Other large scale projects include: Columbia Presbyterian Hospital in repurposing their spaces and increasing their loads and the (Department of Environment Protection (DEP) Wastewater treatment plant in Washington Heights with a service date in 2019 which will restructure 6 feeders in the Harlem Network.

The Seward Park Development in downtown Manhattan has completed 4 of the 6 buildings, with the last 2 being energized by the end of 2020, completing the estimated demand of 9.4 MVA for the 6 buildings. The Seward Park Development is located near the intersection of Essex Street and Delancey Street. The project will allow for 1,000 units of housing, a 15,000-square-foot open space, a new and expanded Essex Street Market, senior housing community facilities, a rooftop urban farm, 250,000 square feet of office space, and a diverse retail space.

Transportation Capital Projects – Including the 2nd Avenue Subway, Fulton Center and East Side Access. The East Side Access (ESA) is a project being undertaken by the Metropolitan Transportation Authority (MTA). It is the first expansion of the Long Island Railroad (LIRR) in over 100 years, and is the largest project of its type in the country. ESA will connect the LIRR's Main and Port Washington lines in Queens to a new LIRR terminal beneath Grand Central Terminal in Manhattan. The East Side Access service is targeted to begin December 2022. Second Ave Subway Phase 2 began in 2017. The project will extend the current 2nd Ave subway line; establishing new stations located at 96th, 106th, 116th, and 125th Streets, which will add approximately 20 MVA of load to the Yorkville and Triboro networks. The New York MTA estimates the project cost to be approximately $6 billion.

The Moynihan station expands Penn Station across 8th Ave into the historic James A Farley Post Office, which is part of a mixed-use development which encompasses an entire city block in relief of existing station crowding and improved passenger comfort. Moynihan Station will be adding 10 MVA to the growing Pennsylvania Network with a service date of late 2018.

Technical School Development – As part of the City's effort to create an environment for small technical start-ups in NYC, the City is providing $100 million towards utility costs to promote the Cornell University Roosevelt Island Campus project. This proposed plan consists of nearly 10-12 buildings with approximately 15 MVA load. The first phase saw 4 buildings with an estimated load of 5 MVA. We plan to provide an interior 460V multibank (above the flood plain). The job was ruled high tension and a 460V transformer was provided at an accommodation cost.

Schools – The Department of Education (DOE) is working against a $12.8 billion capital budget plan. The Department of Education is faced with both a growing student population and aging infrastructure. The current plan will address the need to create more than 39,500 seats in areas of current overcrowding and projected enrollment growth. We expect to see a gradual increase in construction activities.

Brooklyn/Queens

Domino Sugar Waterfront Property – The former Domino Sugar refinery property continues to be re-developed to become one of the most anticipated residential complexes in Williamsburg's waterfront area. Phase 1 of 5 is almost near completion at an estimated demand of 2MVA. This includes a 500,000 square feet residential tower that will be in service by the end of 2018. The complete 5 phase complex will have an estimated load of 14MVA.

Pacific Park Project (Atlantic Yards) – This project consists of 14 mixed-use buildings. Only six of the planned buildings (461 Dean Street B2, 535 Carlton Avenue B14, 550 Vanderbilt Avenue B11, 38 6th Avenue B12) are complete with an encroaching 2025 deadline to complete 2,250 affordable housing units. The following buildings are under construction (615 Dean Street B12 and 664 Pacific Street B15). Phase three (B4) will begin as early as 2019, phase four (B8-10) and phase five (B5-7) should be completed by 2025. The new phases that have not started will have an estimated load of 13 MVA.

Gateway – The Gateway area in Brooklyn is being developed into a large residential community with approximately 750 homes and will include additional commercial load. The anticipated new loads will be approximately 6 MVA. There is currently no electric infrastructure in the area and construction began in 2015 and will continue over the next several years.

LaGuardia Airport - The Port Authority of New York and New Jersey (PANYNJ) is currently proceeding with an extensive program to modernize and expand its facilities at LaGuardia Airport. Two major redevelopment plans for the airport are the LaGuardia Development Program (LDP) and the Delta Expansion Program (DEP). The LDP replaced the existing Central Terminal Building (CTB) with a new and larger CTB. The LDP is scheduled for completion by 2019. The DEP will replace the existing Delta Terminal Building with a new and larger terminal. The DEP is scheduled for completion by 2020. The combined additional load for both programs is expected to be 28.25 MVA.

John F. Kennedy Airport - The Port Authority of New York and New Jersey (PANYNJ) is planning to have JFK redevelopment project and electric vehicle charging station deployment in central terminal location. The development project is including its High Tension (HT) service facilities modernization and consolidation. The combined additional load for both programs is expected to be 10 MVA over next several years.

Bronx

1500 Water Place – There are three major commercial projects in one development area, inclusive of office, medical, and mercantile buildings. The development will also include garages and a football field to further develop upon the Hutchinson Metro Tech Center consisting of newly developed medical, office, college, and the newly opened 911 call center. The new commercial square footage totals 764,361 and the garages are 519,718 square feet. Satisfying the loading requirements of the growing development will require significant feeder reinforcement.

Westchester

17 Skyline Drive, Mt. Pleasant – Tier Point has requested electric service to expand an electronic data center in an existing building located in the Westchester Executive Park at 17 Skyline Drive, Elmsford, New York. The data center is approximately 30,000 sq. ft. The total connected new load consists of 3,752 kVA in data center power and 236 kVA in miscellaneous power. This will be in addition to the existing building load of 564 kVA. The total expected load for the customer is approximately 4.5 MVA. The data center achieved full load in 2018, with a ramp up period extending throughout the following years. The customer will receive an automatic transfer switch and 3-2,000 kVA pad mounted transformers, as well as three PME-5's for the purpose of fault isolation. In addition, we will have to extend aerial feeder cable to the customer's location, and rebuild the existing direct buried underground system in the easement area.

Staten Island

The New York Wheel, Empire Outlets and Lighthouse Pointe – There are 3 large projects near the Staten Island Ferry. They are The New York Wheel, Empire Outlets, and Lighthouse Pointe. These 3 buildings will have commercial space as well as hotel rooms. They had some construction delays and are now expected to be energized by the middle of 2018. These customers will bring an estimated load of 8MW to the system.

Stapleton Waterfront – Phase 2 and phase 3 of the Stapleton Waterfront project is beginning. Phase 1 brought 7 and 8 Navy Pier which are 2 mix used commercial/residential buildings. With Phase 2 and 3 they are continuing to develop the Stapleton Waterfront adding 4 more parcels of land. Each parcel will have a mixed used commercial/residential building with an average of 25,000 Square Feet per building. The end of the development will bring a total load of 5MVA.

Matrix Development - By the Goethals Bridge there is a large development constructing four buildings, each approximately 800,000 Square Feet. These warehouses will be a home to Amazon and all their affiliates. This site will be a major warehouse and distribution site for Amazon. They will have server farms, battery operated machinery, conveyor belts and cranes in these buildings. The developers are looking to energize by late 2018 to early 2019. This development is expected to bring a total of 18MW to the system.

College of Staten Island (CSI) - The property is continuing to expand, adding more buildings and a supercomputer. CSI is currently drawing 6MVA of load via a 2 feeder High Tension. The college is looking to expand their buildings, dormitories and also add a high performance super computer over the next 10 years. We will be providing another feeder to them to support their expansion resulting and an addition of approximately 10MVA.

Staten Island Rapid Transit (SIRT) – The train that connects the south of Staten Island to the ferry terminal is adding more substations along the line to be able to provide more power to the traction system. They are introducing a new line of trains, and expect to have more trains on the line at any given time. They recently energized the Princes Bay substation, and are now beginning work on the Clifton substation, New Dorp substation and the Tottenville substation. Each of these stations will receive a high tension service from our 33KV system.

These projects are representative of the numerous development opportunities planned and underway in our service territory.

Our system load growth is forecasted to only moderately increase over the next several years going forward. This is attributed to significant developments in our Demand Side Management programs, which promote energy efficiency and demand response. We will continue to explore unique solutions that include traditional engineering, operational measures, and a variety of distributed generation, demand management, energy efficiency and other innovative technologies/solutions. Both utility and customer sided solutions will be considered and deployed.

As we analyze the distribution system to connect these new loads, we find that in many cases the existing system is at or beyond its capability and the addition of this load can no longer be served just by extending a service lateral from our distribution system. More specifically, many of these residential and commercial projects require extensive infrastructure such as secondary main reinforcement, primary feeder extensions and transformer vault installations to adequately support these new/additional loads.

Under 100K Retail Projects: The slightly higher construction costs and increased Department of Transportation stipulations will be partially offset by an overall reduction in estimated demand factors utilized to predict future demand of new business customers. We continue to see an increased volume of retail work throughout our service territory with significant economic developed on the retail side in our Brooklyn/Queen area.

	Retail Projects		
	2015	**2016**	**2017**
Actual Dollars($000)	$91,912	$83,841	$84,516
Actual Services	7,292	10,020	10,521
Average Cost per Service	$12,604	$8,367	$8,033

Over $100K Major Projects: The slightly higher construction costs, increased Department of Transportation stipulations, and the selection of less builder-friendly sites, is partially offset by the shift of

larger retail jobs into this category and an overall reduction in estimated demand factors utilized to predict future demand of new business customers.
With the introduction of our "Storm Hardening" initiatives we will experience an increase in the average cost per project since we are installing submersible equipment on all standard 120V major new business jobs moving forward.

	Major Projects		
	2015	**2016**	**2017**
Actual Dollars($000)	$63,015	$70,560	$92,174
Actual Services	443	708	647
Average Cost per Service	$142,246	$99,661	$142,463

Supplemental Information:

Alternatives:
Given the fact that Con Edison has an obligation to serve new customers within the Company's service territory, there are few alternatives to consider regarding New Business Capital. However, the Company considers and reviews specific alternatives on each major project. Our Design Review initiative continues to vet various options and collaborate on the most cost-effective solution. In addition, we have recently completed a comprehensive review of our estimated demand factors resulting in an overall reduction in predicted peak demand. We also continue to incorporate new technologies into our design to help reduce capital spend. These technologies include the use of 18 Pt Terminal Housings & Submersible Bus Equipment. Lastly, Customer Engineering is working closely with the Distributed Engineering Department to develop specifications to incorporate customer sided distributed generation into our design criteria.

Risk of No Action:
"No action" is not an option when it comes to capital spending associated with the connection of new customers. Our future revenue stream and compliance with PSC regulations necessitates the connection of new customers to our system.

Summary of Benefits (financial and non-financial):
While the payback on each new connection varies greatly, each customer represents a contribution to the revenue stream that ensures the financial viability of our business.

Non-financial Benefits:
To support customer satisfaction by ensuring regular communication with customers requesting new and additional energy supply. In addition, guaranteeing a safe, reliable, efficient, and timely installation of service.

Summary of Financial Benefits (if applicable) and Costs:
The New Business Capital program permits us to proactively evaluate customer requests to add new or additional load to our electric distribution system. While maintaining a safe, reliable, and efficient design criterion in accordance with Company specification, our analysis allows us to develop the most cost effective service design that meets our customers' service needs.

Technical Evaluation/Analysis: N/A

Basis for Estimate: Historic Unit Cost

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	32,413	38,049	40,001	39,973		34,819
M&S	18,159	23,513	22,505	24,727		18,807
A/P	34,994	40,014	46,228	59,422		50,925
Other	(20,225)	(27,872)	(18,177)	(8,202)		-
Overheads	66,984	81,223	63,855	60,771		51,292
Total	**132,325**	**154,927**	**154,412**	**176,691**		**155,843**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	25,900	24,361	25,975	25,835	26,481
M&S	31,953	33,218	32,762	34,447	32,528
A/P	25,405	35,089	36,035	36,145	36,917
Other	23,024	23,530	23,772	23,344	23,648
Overheads	51,912	48,532	46,455	48,229	48,426
Total	**158,193**	**165,000**	**165,000**	**168,000**	**168,000**

Schedule 4:

T&D Capital White Papers

System Expansion

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Primary Cable Crossing (XW City Island , Riverdale Croton River, and BQ Flushing)
Project Manager	Timothy Schlauraff & Stephen Maikisch
Hyperion Project Number	PR.MED3028 , PR.9ED0271
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	2028
Work Plan Category	Strategic

Work Description:
This program will reinforce cable crossings in the Flushing and Riverdale networks and in two radial areas consisting of City Island in the Bronx and the Village of Croton-on-Hudson in Westchester.

A description of the work proposed for the Flushing Network follows:
The Flushing load pocket is located two miles from the Corona No. 1 substation and the feeders cross various geographical obstructions. Two of the crossings run over the Grand Central Parkway, one of the crossings runs over the Horace Harding Expressway and two of the crossings run on bridges over the Flushing River. With load forecasted to increase in the Flushing Network, three feeders at one of the Grand Central Parkway crossings will be overloaded and will need installation of baskets to resolve these overloads. The other crossings need additional installation of duct to maintain the reliability of the electrical system in case of any unforeseen feeder faults or damage.

Based on loading and availability of spare ducts, we plan on doing reliability work on two (2) crossings in the next five years in this order:

1) Northern Blvd Bridge and College Point Blvd:

The crossing has 2-27 KV feeders inside a high pressure steel pipe going under the Flushing River. With this current configuration, the reliability for both feeders is compromised in an event of a fault within the crossing. Re-routing one of the feeders away from the high pressure steel pipe will improve reliability.

Additionally, the crossing has 2-4 KV submarine cable feeders going under the Flushing River. These 2 feeders need to be rerouted to improve the reliability of the system.

Proposal:
The anticipated work required for the re-routing of the 27 kV feeder includes 65 ft. of conduit and 7 sections of primary cable. The anticipated work required for the re-routing of the two 4 kV feeders to eliminate the submarine cable includes installing 25 sections of cable. Cost will include outside engineering consulting.

The projected cost for this project is **$2 M.**

2) Roosevelt Avenue and the Flushing River:

This crossing has one system located on the south side with 4 feeders and is located on an elevated structure that runs along the #7 subway line. The system is an aerial cable installation, suspended under the structure. To increase the reliability of the system, 8 conduits will be installed on the sidewalk and two aerial feeders will be re-routed to this system.

Proposal:
The anticipated work for this project includes 1,200 ft. of conduit and 8 sections of cable.
Costs will include outside engineering consulting.

The projected cost for this project is **$3.4 M**.

3) Roosevelt Ave. and Grand Central Parkway

This crossing has 2 systems, a northern system and a southern system with 4 feeders each and various locations of spare conduits. To increase the reliability of the system, installation of spare conduits on the north and south system will be done.

Proposal:
The anticipated work required for this project includes 800ft. of conduit in two systems installed under the structure and 6 sections of cable. Costs will include outside engineering consulting.

The projected cost for this project is **$4.0 M**

4) Horace Harding Expressway (Long Island Expressway) and the College Point Boulevard:

This crossing has two systems, a northern system with 4 feeders and a southern system with 4 feeders. Neither system has any spare conduit. To increase the reliability of the system, installation of spare conduits on the north and south system will be installed via directional drilling if feasible.

Proposal:
The anticipated work for this project includes 600 ft. of conduit in two systems installed under the structure and 4 sections of cable. Costs will include outside engineering consulting.

The projected cost for this project is **$3.2 M**.

5) 44th Avenue & Grand Central Parkway

This crossing has two systems, a northern system with 2 feeders and a southern system with 3 feeders. Neither one of these systems have spare conduits. To increase reliability of the system, installation of spare conduits will be done based upon design chosen.

Proposal:
The anticipated work for this project includes 400 ft. of conduit in two systems installed under the structure and 4 sections of cable. Costs will include outside engineering consulting.

The projected cost for this project is **$2.4 M**.

A description of the work proposed for the City Island, Riverdale Network and Croton River Crossings are as follows:

1. City Island is supplied by four 4kV feeders originating from three different networks (Washington Street, Cedar Street, and Southeast Bronx) to allow for increased reliability on the island. Two of the feeders, 7207 and 5361 enter the island via submarine cable on the seabed of the Hutchinson River, adjacent to the Pelham Bridge drawbridge. The cable on the seabed is vintage aerial cable associated with the two feeders installed over 40 years ago. Previous inspections have found that the cable has exceeded its useful life and should be replaced. The proposed solutions include replacing the cable with a newer submarine cable, directional boring under the Hutchinson River, or the complete elimination of the crossing. A feasibility study will need to be performed to identify the most cost effective option among directional boring, submarine cables or conversion to 13 kV (which would eliminate the need for this crossing). Costs will include outside engineering consultation for a feasibility study, a geotechnical study, and a final design plan if necessary.

   The projected cost for this project is **$3.8 M**

2. Currently there are twelve feeders in the Riverdale Network that originate in Manhattan's Sherman Creek Substation and feed the Riverdale area in the Bronx. Eight feeders are still in need of replacement. These eight feeders (1X23, 1X24, 1X25, 1X26, 1X27, 1X28, 1X29, and 1X30) supply approximately 67 % of the Riverdale network as well as the Riverdale Auto loop. For the Riverdale Network, the existing submarine cable crossings for eight 13 kV feeders will be replaced via two new crossings. Each river crossing will contain eight ducts housing four feeders with one spare per feeder. Each feeder will have new modern and more resilient 1000 mcm Ethylene Propylene Rubber (EPR) cable with ducts installed below the seabed. River crossings for four of the 12 Riverdale network feeders have already been relocated into the M29 tunnel. A feasibility study was completed and a consultant hired to perform soil borings and geotechnical baseline reports as well as design plans and a profile of the river crossings. River and land borings will begin in the first quarter of 2018. Costs include outside engineering consulting.

   The projected cost for this project is **$5.0 M per crossing**

3. For the village of Croton-on-Hudson, the existing submarine cable crossings for feeders 6W62 and 6W69 under the Croton River will be replaced. The project will install conduits under the Croton River and retire the old submarine cables. The RFP for the feasibility study was completed and an engineering contractor has been selected and is developing a horizontal directional drilling plan. Six 5" conduits will be installed via horizontal directional boring and new 750 circular mil (MCM) EPR cable will be installed in these conduits. Costs for two feeders include outside engineering consulting

   The projected cost for this project is **$3.7 M**

Justification Summary:
This project addresses the construction of additional crossings based upon the need to provide primary capacity to the specific load pockets supplied.

For crossings projected to become overloaded, such overloads must be relieved as overloaded cables have a greater likelihood of failing and will impact system reliability. For crossings that have no spare conduits, failures of the existing feeders will impact system reliability since there would no longer be a path to transfer power across the crossing and the time to build a replacement crossing is lengthy.

For the Flushing network, the crossing discussed previously is projected to become overloaded and must be relieved either by installing larger cable or additional conduit systems. The current design plans are to install additional conduit systems to avoid delays due to cable becoming obstructed during attempts to remove it. In addition, the existing cable conduits are made of asbestos containing material and would require shutting down lanes of traffic on the Grand Central Parkway in order to remove them and install larger conduits.

For City Island in the Bronx, the cable on feeders 5361 and 7207 that supply City Island in the Bronx is of an older vintage that was installed in 1975. This cable was inspected in the past and was found to be beyond its useful life. A failure of any of these cables would result in extensive voltage and load support issues on the City Island loops, and potentially lengthy customer interruptions. Repair times for these feeders will also be long as they will require cable in lengths beyond normal standards, special permits, and equipment not normally used by the Company.

In the case of the Croton River crossing, there are two 13 kV feeders that supply approximately 4,500 customers. They both contain sections of 3-conductor 800Kcmil submarine cable. Over the years, all spare cable ducts that existed in this crossing have failed and are unusable. If another failure should occur, there will be no way to restore the feeder to service. This would severely jeopardize electric service to the 4,500 customers.

The cables supporting seven of the eight remaining Riverdale crossings were installed in 1913 and 1946. The eighth feeder was replaced in 1982 in an emergency by laying two sets of cable directly on the riverbed. Over the years, due to subsequent failures, the remaining spares have been used such that each feeder has only one spare with no means to readily install replacements. The age and the location of the existing crossing cable makes these cables prime candidates for failure with no means to replace them.

<u>Supplemental Information:</u>

- <u>Alternatives</u>:
  All System Expansion projects will be reviewed for Non Wires Solution in accordance with the suitability criteria outlined in the DSP.

  The alternative for the Flushing Network suite of projects would be to either eliminate the projected overloads of the crossings or to supply the Flushing network requirements with new feeders that do not utilize crossings. Eliminating the projected overloads for the Flushing network crossings would require de-loading moves such as swapping transformers to alternate feeders or possibly transferring load out of the Flushing network to an adjacent network. De-loading moves would require installation of new underground and overhead infrastructure, which would be significantly more costly than the proposed conduit installations. Transferring load out of the Flushing network to an adjacent network is not a practical solution. Load transfers also require installation of significant new infrastructure and are typically cost justified only for larger load transfers than those necessary for this project.

  The alternatives for the Riverdale and City Island projects would be to replace the cables upon failure be subject to a lengthy time out of service while the new crossing is constructed and find alternative methods to meet capacity needs.

  For the Croton River crossings, an alternate plan of extending two 13 kV feeders from Buchanan Substation into the Croton area was considered. These feeders could be used to supply the Croton Unit Substation, a portion of the Croton Auto-loop and a portion of the MTA load at Croton Harmon. The estimated cost of extending these two feeders is $6 million. Due to the significantly higher cost of this plan, it was rejected in lieu of the plan to bore under the Croton River to replace the two existing submarine cables.

- Risk of No Action: Without new crossing conduits, the feeder sections contained in the crossings mentioned above will overload as the Flushing Network's load continues to grow. If the overloaded feeders are not relieved, there will be a greater risk of network outages due to cascading feeder failures associated with high feeder loadings. For the Croton River and City Island crossings there would be a significant impact to system reliability if any of those feeders fail and cannot be replaced.

- Non-financial Benefits: This suite of projects provides overall reliability benefit as they either incorporate additional capacity into the primary distribution system and/or provide additional spare conduits to address future failures and allow restoration of service more quickly.

  When the feeder crossing sections are replaced some Paper Insolated Lead Cover Cable (PILC) will be replaced and the associated stop joints will be replaced, further increasing the reliability of the network.

- Summary of Financial Benefits (if applicable) and Costs: Relieving overloaded primary feeders in the crossings mentioned above will increase network reliability and reduce the risk of network shut down. Costs associated with network shutdowns such as restoration costs, and regulator penalties ($10 million penalty per network shutdown) are minimized.

  For some of the crossings, additional spare conduits will be installed as it is most cost effective to install sets of four or eight conduits at a time. This will minimize future costs associated with future feeders in the area and minimize restoration cost associated with a feeder failure in a crossing.

- Technical Evaluation/Analysis: See work description

- Project Relationships (if applicable): The planned feeder crossing projects address overloaded sections of primary feeders, which would otherwise (if not located in a crossing) would be addressed as part of the Primary Load Relief program.

- Basis for Estimate: The basis for the various cost estimates are detailed in the work description and utilize standard unit costs for conduit, structure and cable installation where applicable, as well as previous actual project costs where available.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	489	24	143	121		252
M&S	121	-	1,077	137		419
A/P	24	74	2,910	1,798		2,352
Other	4	10	6	7		230
Overheads	484	93	1,921	1,086		991
Total	**1,122**	**201**	**6,057**	**3,149**		**4,244**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	167	348	399	71	71
M&S	285	594	448	120	120
A/P	1,162	2,423	819	491	491
Other	42	87	347	18	18
Overheads	743	1,548	643	314	314
Total	**2,399**	**5,000**	**2,656**	**1,014**	**1,014**

X	Capital
	O&M

2019 – Central Operations / Substation Operations

Project/Program Title	East 179th Street - Switchgear and Bus Replacement
Project Manager	John McCoy
Hyperion Project Number	5ES1900
Status of Project	In Progress
Estimated Start Date	2010
Estimated Completion Date	2022
Work Plan Category	Operationally Required

Work Description:
The East 179th St. area substation is nearing the end of its useful life, with load relief needed by 2019. This program is required in order to replace/upgrade the switchgear, bus and associated wiring to maintain the reliability of network load area supplied by this substation. A study was completed to evaluate two possible replacement options:

1. Replace the switchgear and wiring in its current setting
2. Construct a new switchgear building and install new switchgear indoor.

A third option of transferring load to a nearby substation and retire the existing station was determined to be not feasible due to lack of spare capacity at nearby stations.

Option 1 has been selected and approved.

This project is being coordinated with the transformer replacement program scheduled at E179th St., reflecting an overall revised completion date of 2022.

Justification Summary:
The station was placed in service in 1956 and it is one of the few area stations with outdoor switchgear and underground protection and control equipment. Because it is an outdoor substation, the weather has taken its toll on the physical structures that house the equipment as well as its wiring. In addition, switchgear support members have become severely corroded due to poor drainage which reduces the reliability of the switchgear equipment. The drainage issue also creates a potential safety issue if crews have to work on the electrical equipment while standing in water. The ultimate plan is to upgrade the entire 13 kV switchgear, 13kV bus, relay systems, control wiring and site drainage.

In addition to the station's equipment condition issues, which supplies the central and North Bronx area of New York, the East 179th station forecasted to experience load demand exceeding its existing capacity in 2019. All nearby stations are at or near capacity and therefore load cannot be transferred. The only alternative is to upgrade the capacity of the existing station.

Supplemental Information:

- Alternatives: Two alternatives to this program were considered.

Alternative #1 evaluated refurbishing the existing substation switchgear with retrofitted breakers, new relays and upgraded wiring. This alternative was rejected since it did not include upgrading the 13kV bus (underrated), resulting in the new equipment rating not matching the capability of the new transformers being installed. It also did not provide provisions for future growth, eliminate existing over duty of switchgear, nor did it include housing for new high voltage test sets or separation of the 125VDC systems.

Alternative #2 included the replacement of the existing switchgear with standard double syn bus 5-section indoor switchgear in a new building. This option was rejected due to higher costs, and required extensive community outreach. Due to residential zoning requirements, an extensive permitting process would be required without a guarantee that permitting and construction could meet the load relief date.

This project has undergone asset-related screening following the criteria proposed by Con Edison along with the Joint Utilities in our comments on the Staff Whitepaper on Benefit Cost Analysis. The screening criteria proposed consist of four tests that would be used to filter projects that should or should not be considered for a Non Wires Alternative (NWA) solicitation. Any project that meets all four criteria would be considered a candidate for an NWA cost effectiveness analysis that would compare the NWA cost to traditional utility infrastructure alternatives to determine if an NWA should be pursued. The screening criteria are:

1. Cost is > $5,000,000
2. Project completion is expected at least 36 months or more out
3. Required load relief is less than 10 % of the load in the area
4. Work not related to asset condition

This project does not meet criteria on 3 and 4, thus an NWA effectiveness cost analysis was not conducted.

- Risk of No Action: No action would continue to degrade switchgear support members, which have become severely corroded due to poor drainage, and reduces the reliability of the switchgear equipment. The drainage issue also creates a potential safety issue if crews have to work on the electrical equipment while standing in water.

- Non-financial Benefits: One important benefit is the ability to address flooding in the station, allowing safer switching operations. Additionally, the new equipment will increase load capability of the station, eliminate circuit breaker fault duty interrupting deficiency, improve customer restoration duration due to the new equipment, and increase operating reliability with the new double syn bus design.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: A technical study to evaluate two possible replacement options, as noted in the Work Description, was completed by an outside consultant and approved by Engineering. The results of the technical study recommended the replacement of the switchgear, bus and wiring.

- Project Relationships (if applicable): The switchgear and bus replacement is being coordinated with the transformer replacements also planned for E179th St., and funded under the transformer replacement program.

- Basis for Estimate: Future expenditures are based on an Order of Magnitude Estimate

Annual Funding Level ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	2,400	3,756	153		1,272
M&S	-	1,027	544	155		492
A/P	-	2,723	864	54		428
Other	-	233	316	22		61
Overheads	-	4,430	3,773	162		1,035
Total	**-**	**10,814**	**9,254**	**546**		**3,287**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	2,855	3,416	2,796	6,218	-
M&S	776	976	725	2,021	-
A/P	1,746	1,964	1,491	3,333	-
Other	903	978	751	1,571	-
Overheads	3,421	4,866	4,594	9,068	-
Total	**$9,700**	**12,200**	**10,357**	**22,211**	**-**

X	Capital
	O&M

2019– Central Operations / Substation Operations

Project/Program Title	Hudson Ave DSS.
Project Manager	TBD
Hyperion Project Number	PR.23291581
Status of Project	Engineering /Planning
Estimated Start Date	2020
Estimated Completion Date	2022
Work Plan Category	Operationally Required

Work Description:
A distribution switching station project is planned with two 138/27kV transformers (supplied from 138kV Hudson Ave East Transmission station) creating an additional supply source for Plymouth and Water St. stations before the summer of 2022. The additional supply source is created through a 27kV bus extension at Plymouth St. and Water St. that connects to the two 138/27kV transformers to increase the stations capability. The two new transformers supplied from Hudson Ave East will increase Plymouth St. capability from 373 MW to 502 MW and Water St Stations capability from 373 MW to 509 MW.

Justification Summary:
Plymouth St. and Water St stations are projected to develop a 2MW capability shortfall in 2022 which traditionally would be addressed by adding transformer cooling at Plymouth St., Water St, Farragut Station, and by uprating Plymouth St. subtransmission feeders. In 2025, Plymouth St. and Water St Stations are project to again develop overloads that will require the expansion of Gowanus Transmission Station and the new Nevins Area station.

The Hudson Ave distribution switching station (DSS) will provide additional capability to Plymouth St. and Water St stations eliminating the transformer cooling projects, the subtransmission feeder upgrades and the need for expanding Gowanus Station and the new Nevins Substation. The Hudson Ave DSS project will provide the capacity needed and is the least cost option to meet the projected shortfall in 2022 that will continue to increase in subsequent years. This project will provide additional station capacity, and is expected to serve the station's capability needs beyond 2038.

The Company will review all System Expansion projects to determine the Non-Wires Candidates as part of the Distribution planning process. The Company will then provide information regarding these candidates and their progress on its website as well as via periodic NWS filings.

Supplemental Information:

- Alternatives: One alternative would be to install transformer cooling on all area stations (Water St and Plymouth St) transformers and uprate the subtransmission Plymouth St. feeders by 2022. In addition, expand Gowanus transmission station and establish the new Nevins Area station by 2025. However, all the above projects are expected to be a costlier option due to the amount of work that would be required to establish a new area station.

- Risk of No Action: If no action is taken, there would be a potential risk of losing customers due to the higher network load as compared with the station capability.

- Non-financial Benefits: Ensures continued and uninterrupted service to our customers. Maintains Con Edison's system reliability.

- Summary of Financial Benefits (if applicable) and Costs: NA

- Technical Evaluation/Analysis: Based on Area Station Planning's load flow and forecast analyses, Plymouth St. and Water St Substation are projected to develop a 2 MW capability shortfall in 2022 that increases in subsequent years. If left unaddressed the shortfall would be 19 MW at Plymouth St. and 50MW by 2024. The new Hudson Ave DSS will provide additional capacity to support the load increase in that area and the stations capability will be 502 MW at Water St. and 509MW at Plymouth St. station. This new DSS installation at Hudson Ave will provide the least cost option to meet the station projected loads through 2038 and beyond.

- Project Relationships (if applicable): There are no associated projects with the new Hudson Ave Distribution Switching Station project.

- Basis for Estimate: Approved Appropriation Estimate

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	350	12,015	24,110	24,546	
M&S	250	8,560	17,120	17,355	
A/P	128	4,383	8,766	8,874	
Other	99	3,424	6,850	6,925	
Overheads	173	5,858	11,634	11,780	
Total	**1,000**	**34,240**	**68,480**	**69,480**	**-**

X	Capital
	O&M

2020– Electric Operations

Project/Program Title	Load Transfer Newtown to North Queens
Project Manager	Ramze Muntasser
Hyperion Project Number	PR.23492034
Status of Project	Planning
Estimated Start Date	Fall 2019
Estimated Completion Date	Spring 2022
Work Plan Category	Operationally Required

Work Description:
To de-load the Newtown sub-transmission feeders, the Company plans a transfer of approximately 40MW from Newtown Substation to North Queens Substation. 40MW's of load from the northern portion of the Borden (2Q) network was selected due to its geographical location. The design involves extending 10 network feeders from Long Island City to the Borden network. Ten feeders in the Borden network will be split to accommodate the transfer. The southern border of Long Island City network will be extended all the way to the new cutline following 44th Road in the south. The west and east boundaries are the natural cutline provided by The East River and Jackson Ave (boundary with Sunnyside Network). In order to accommodate this load, 12,612 feet of primary & secondary conduit, 110 sections of primary cable, 48 structures, 7 network transformers, 20 primary switches and 117 sections of secondary cable will be installed.

Justification Summary:
A load transfer of 40 MW's from the Newtown Substation to the North Queens Substation is required prior to the summer of 2022 to avoid overloading both the Newtown Substation and the sub-transmission feeders supplying it. The transferred load will be added to the Long Island City network supplied by North Queens substation.

The load projections in the "2018-2027 Area Substation and Sub-transmission Feeder Ten-Year Load Relief Program" indicates that both the Newtown area substation and the 138 kV sub-transmission feeders supplying the Vernon/Glendale/Newtown load pocket will exceed their capabilities by the summer of 2022. The overloads occurred as result of the load growth in the Borden network, the Newtown Substation load will be 248 MW's by summer 2022, which exceeds the 244 MW capability of the substation by 4 MW (102%). This overload continues to grow as load increases in the ensuing years. Exceeding the capacity of the substation and transmission feeders could result in load shedding if contingencies occur during peak loading conditions. This would result in customer outages and increases the risk of equipment failure presenting and adversely impacting the community served.

This load transfer project will deload both the Newtown substation and the 138 kV supply feeders allowing them to operate within their thermal capability limits and provide enough capacity for future load growth.

Supplemental Information:

- Alternatives: All System Expansion projects will be reviewed for Non Wires Solution in accordance with the suitability criteria outlined in the DSP

  Installation of fourth transformer and 138 kV supply feeder 38Q05 from Vernon (east bus) to increase area substation capability from 244MW to 361MW by 2022.

- Risk of No Action: An overload on the sub-transmission feeders supplying Newtown Substation is predicted to occur starting in 2022. In the event the sub-transmission feeders overload, load shedding would be required during peak load conditions.

- Non-financial Benefits: The benefits of the project are the relief of both the substation and transmission feeders, which will ensure continued reliable service to the Newtown load pocket.

- Summary of Financial Benefits (if applicable) and Costs: As discussed above, multiple alternatives were considered in-order to relieve the Newtown load pocket and the selected option is the least expensive.

- Technical Evaluation/Analysis: In general, infrastructure adequacy is determined by comparing the infrastructure capability, in this case the transmission system supplying the Newtown load pocket, against the net load to be served. The net load is determined from the gross forecasted customer demand less any load relief measures such as existing and forecasted energy efficiency or local distributed resources in the network.

  Poly Voltage Load flow (PVL) was utilized to determine any distribution cable and equipment overloads around the cutover area. The PVL case was scaled up to match the forecasted load growth for the summer of 2022.

- Project Relationships (if applicable):

- Basis for Estimate: Historical unit costs.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	987	2,008	308		-
M&S	1,004	4,956	279		-
A/P	1,082	8,020	444		-
Other	947	2,200	259		-
Overheads	1,280	6,816	511		-
Total	**5,300**	**24,000**	**1,800**		**-**

X	Capital
	O&M

2020 – Electric Operations

Project / Program Title	Load Transfer W42nd St to Astor
Project Manager	Albert Wang
Hyperion Project Number	PR.23244647
Status of Project	In Progress
Estimated State Date	2019
Estimated Completion Date	2021
Work Plan Category	Operationally Required

Work Description:

To avoid overloading the W.42nd St. No. 1 Substation that supplies the Pennsylvania network (16M) in Manhattan, 55 MW of load is to be transferred from W.42nd St. No. 1 Substation to Astor Substation prior to the summer of 2021.

This will be accomplished by establishing a new network that will be supplied from Astor Substation. The new network will be created by transferring out the Hudson East Yard portion of the Pennsylvania network. The network will initially be created as an 8 feeder network using vacant cubicle positions at Astor Substation.

The boundaries of the proposed new network will be W.33rd St to the North and W.30th St. to the South; 10th Avenue to the East and 11th Avenue to the West. There is no secondary main reinforcement required since the new network consists of high tension service and 460V service only.

The completion of this work will result in the West 42nd Street No. 1 Substation having a loading of 220 MW versus a capability of 262 MW (84%), and Astor Substation having a loading of 157MW versus a capability of 179MW (88%) for the summer of 2021.

Estimated Units:

Conduit: 13,000 ft.
Primary: 124 sections
Secondary: 0 sections
New Structures:22 structures
Substation Cubicles: 8 existing cubicles

High-level schedule: Work on the W.42nd St No. 1 to Astor transfer is scheduled between the early part of 2019 (field surveys, engineering, and some sub-surface construction) through the second half of 2020 with the intermesh and clean-up taking place prior to the summer of 2021.

Justification Summary:

Based on the “10 Year Load Forecast” the area substations and sub-transmission feeders in the W.49th Street load pocket are projected to exceed their capability by the summer of 2021. The Pennsylvania network will reach 275 MW by the summer of 2021, which exceeds the 262 MW capability of the W.42nd Street No. 1 Substation by 13 MW (105%).

The main driver of this project is the significant new business load growth in the Pennsylvania Network. Examples of the new load growth include Hudson Rail Yards, Brookfield Properties and several skyscrapers along the newly constructed Hudson Blvd. It is also expected that the No. 7 Subway Line extension to W.34th St and 11th Ave will play a significant role in the areas load growth by attracting new tenants to this neighborhood.

This project will result in West 42nd Street No. 1 Substation operating within its capability and maintaining capacity for future load growth. This proposed transfer utilizes vacant station feeder cubicles at Astor Substation, which was completed in 2009.

Supplemental Information:

- Alternative Solution:
  The alternate solution to de-load W.42nd Street No. 1 would be to transfer a portion of the Pennsylvania network to an existing adjacent network. There are six networks that border the Pennsylvania footprint. However, all of them are supplied by substations that do not have the capability to accept a 55 MW load transfer. Therefore, multiple load transfers involving different transmission load pockets would need to be performed to achieve a similar result. The total cost for an alternate plan involving two or more load transfers would exceed $40M.

- Risk of No Action:
  All System Expansion projects will be reviewed for Non Wires Solution in accordance with the suitability criteria outlined in the DSP

  The company is at risk of shutting down an electric distribution network (relatively low risk) or experience an extended outage for a significant number of customers (low to moderate risk) or the risk of a prolonged loss of an area substation at W. 42nd Street No. 1 (relatively low risk). The 10 year load forecast projects that W. 42nd Street No. 1 will be overloaded by 42 MW in the year 2027 if this transfer is not performed.

- Summary of Financial Benefits and Costs:
  Establishing a new network improves the Network Reliability Index (and thus the reliability) of the Pennsylvania network utilizing the newly constructed feeder positions at Astor Substation. It also improves the reliability at W. 42nd Street No. 1 area substation by de-loading the substation. This translates to lowered customer outage costs, and, potentially avoids the high costs of a significant network or substation event.

- Non-financial Benefits (if applicable):
  Helps prevent the negative publicity of a large customer outage, network outage or area substation outage in midtown Manhattan.

- Technical Evaluation/Analysis:
  Poly Voltage load flow (PVL) and network reliability index considerations were utilized to determine the best solution.

- Sensitivity Analysis (if applicable): Not applicable

- Project Relationships (if applicable):
  This transfer is conjunctional with the new feeders that are currently being established to supply the Hudson Yard area with bifurcation at the feeder breakers (the “M” legs are designed to supply

the Hudson East Yard area and the "L" legs are designed to supply the Hudson West Yard area). These new feeders will be de-bifurcated, and the "M" legs will be extended to Astor area substation to establish the new network. The transfer will also relieve the feeder breakers that are projected to be overloaded as the Hudson West Yard load continues to realize through 2025.

- Project Status: Design

Financial Overview/Cost Efficiency: For the reasons described above, this project was deemed the most efficient means to relieve the overload at West 42nd Street No. 1.

Benefits/Outcome of Program/Project:
Establishing a new network improves NRI (and thus the reliability) of the Pennsylvania network utilizing the vacant feeder positions at the newly constructed Astor Substation. It also improves the reliability at W. 42nd Street No. 1 area substation by de-loading the substation.

Non-financial Benefits (if applicable): Helps prevent the negative publicity of a large customer outage, network outage or area substation outage in midtown Manhattan.

Is this a mandated program? If yes, include verbiage associated with mandate:
No.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	46	84	243	42
M&S	-	345	648	1,841	324
A/P	-	616	1,956	3,284	978
Other	-	103	261	547	130
Overheads	-	391	1,051	2,084	525
Total	**-**	**1,500**	**4,000**	**8,000**	**2,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Network Transformers Relief
Project Manager	Various
Hyperion Project Number	PR.4ED0101, PR.4ED4021, PR.4ED1041, PR.4ED3061, PR.4ED7091
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program funds the installation costs associated with providing relief to network transformers whose projected load exceeds their rating.

Network transformers step down primary distribution supply voltages to customer-level voltages. Transformers and associated network protectors have loading limits as described in Con Edison engineering specification EO-2002: *Loading Limits for Network Transformers and Associated Protectors*. The network transformer load relief program funds projects that relieve projected overloads.

Figure 1: Network Transformer and Protector

Relief projects include the following:

- Replacing an existing transformer with a new transformer of the same design, but with a slightly higher rating
- Replacing an existing transformer with a larger transformer with a significantly higher rating (may require vault enlargement)
- Establishing a new vault and installing a new transformer to reduce the loading on the nearby transformers

Justification Summary:

A 1961 Public Service Commission order adopted the PSC staff's recommendation for a second contingency design of the low voltage networks in certain areas. In order to increase the reliability of the secondary distribution networks and meet second contingency design requirements in those areas, it is necessary to have in place network transformers (which supply the secondary distribution networks) that can be loaded within design limits – during both normal and contingency conditions. The objective of this program is to have network transformer loading meet the design specified in EO-2002: *Loading Limits for Network Transformers and Associated Protectors*. Relieving network transformers that are projected to operate above their normal and contingency ratings will maintain feeder stability, resulting in reliable service during peak summer conditions.

Currently, transformer relief undertaken for network transformers follows a one-year electric distribution planning cycle. When the summer load forecast projects overloads of either cable or equipment, the one-year planning cycle targets network or radial feeder and network transformer projects to be completed prior to the summer that the load is expected to overload the system.

Supplemental Information:

- Alternatives:

  Distribution Engineering and Con Edison's 3G group developed an innovative alternative for network transformer load relief. This alternative involves strategically disconnecting underground cable to shift load between transformers. By adding a low voltage switch to disconnect the secondary cable and shift demand, the projected loading for a transformer can be reduced.

  As a result of the New York State Reforming Electric Vision (REV) and the availability of Distributed Energy Resources (DERs) on the system, network transformer relief is moving to a multi-year electric distribution planning cycle. The multi-year electric distribution planning cycle references using operational methods if feasible to solve overloads and defer completing reinforcement projects that would solve the overload of either cable or equipment. Examples of operational measures include use of emergency primary feeder switching, installation of generators, demand reduction or monitoring of and cooling when necessary for network transformers. By deferring these reinforcement projects for one year, there is a greater possibility that a renewable energy source, DERs or other non-wires solution may come in to service and solve the overload condition and eliminate the need for the project. CECONY's Chief Engineer, Regional Engineering, reviews all reinforcement projects and determines whether projects can be deferred for an additional year through the use of operational measures.

- Risk of No Action:

  Transformers that operate at or over their design temperature for extended periods of time are susceptible to degradation of their internal components (e.g., insulation). This degradation can lead to a decrease in the transformer's service life and increase in the risk of premature failure. In an extreme event, a transformer failure can cause additional failures in the network, and a network shutdown.

  Con Edison's network transformers are installed in underground vaults and manholes in public areas. When a network transformer fails, the transformer may rupture, and oil may escape from the vault; this can result in public injury and/or property damage.

  Also, transformer overloads compromise the reliability of the network. During summer months, sustained overload of a network transformer could ultimately lead to Con Edison performing load reduction actions, and may even result in customer outages.

- Non-financial Benefits:

  Network transformer load relief reduces the risk of customer outages and network transformer failures by improving system reliability and public safety.

  Replacing older overloaded transformers with higher capacity transformers also has the added benefit of the newer, safer transformer designs that are now in use (e.g., high fault energy tanks). The high fault energy tanks are able to withstand higher internal pressures, thus minimizing the risk of tank ruptures because of internal electrical faults. When the design pressure is exceeded, the tanks will rupture at the bottom of the transformer cooling panels. This effectively prevents heated fluid or fire from being ejected through the structure gratings and onto the streets, reducing the risks of public injury and/or property damage.

- Summary of Financial Benefits (if applicable) and Costs:

  Network transformer load relief prioritization is assigned according to Con Edison Electric Operations Procedure EOP-5314: *Electric Operations—Engineering and Design: ED-1 Budget Prioritization*. The criteria used to determine the priorities include: projected loading, age of transformer, network reliability index, availability of pressure, temperature and oil sensors on transformer, and load relief options (replacement versus new vault).

- Technical Evaluation/Analysis:

  Regional Engineering groups conduct a load study annually after the peak load period. The most recent load flow models are used. Increases in demand due to load growth, actual load cycles experienced during the peak and potential reduction in demand due to demand side management initiatives are factored into each model. A list of potentially overloaded transformers is generated for normal and contingency scenarios. Regional engineering evaluates different options to relieve the key transformers, as identified through the prioritization process. These options include:

  - Making secondary reinforcement or changing primary feeders
  - Replacing an older unit with a new transformer with higher ratings
  - Replacing the transformer with a larger transformer with greater capacity
  - Installing a new transformer with associated structure and secondary connections

  Regional Engineering proceeds with the most cost-effective option. These units are addressed prior to the next peak loading period unless operational measures are available.

- Project Relationships (if applicable): Transformer Purchase Program

- Basis for Estimate:

  The basis for the estimates used for this program is the historic transformer installation unit cost as well as the projected volume by region.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	2,102	867	977	2,086		1,814
M&S	1,847	434	568	1,692		1,455
A/P	1,330	344	490	1,885		2,016
Other	14	1	13	18		641
Overheads	3,943	1,296	1,250	2,818		2,627
Total	**9,236**	**2,942**	**3,298**	**8,499**		**8,553**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,760	2,987	2,987	3,069	2,093
M&S	1,345	2,282	2,282	2,151	2,004
A/P	1,360	2,309	2,309	2,182	2,241
Other	154	262	262	104	267
Overheads	2,677	4,543	4,543	4,876	5,177
Total	**7,296**	**12,382**	**12,382**	**12,382**	**11,782**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Nevins Street Battery Storage and Electric Vehicle Charging
Project Manager	Mohamed Kamaludeen
Hyperion Project Number	PR.23443506
Status of Project	In-Progress/Engineering/Planning
Estimated Start Date	01/2019
Estimated Completion Date	12/2021
Work Plan Category	Strategic

Work Description:

Con Edison recognizes that energy storage ("ES") paired with electric vehicles ("EV") charging stations has the potential to provide significant operational value and societal benefits to the grid and customers through multiple value streams. The Company has initiated a plan in alignment with the state storage goals of 1500 MW by 2025[1] by proposing to install storage at six Company owned facilities and proactively promoting EV adoption. This whitepaper describes a proposed project that satisfies both objectives - the "Make Ready" concept of ES that seeks to facilitate and streamline installation of storage through developing sites with interconnection and site-ready infrastructure, plus enabling development of publicly accessible EV charging infrastructure that can enhance EV adoption while potentially minimizing strain on the grid from the increased charging load.

The Company is proposing to develop its Nevins street property located in Brooklyn under this "Make – Ready" concept in which the land will be readied to accommodate a third party owned energy storage system and electric vehicle charging stations. The lot will be developed into standardized docking stations for turn-key storage and EV charging installations. This site will be able to accommodate up to about 10 MW/40 MWh peak demand/energy capability. The achievable MW/MWh values can vary as it is a function of the discharge period (that is, if the discharge outside the network peak hour is assumed). The most suitable discharge period will be determined during the engineering study and will appropriately consider any operational restrictions which will be identified during design/testing. Make Ready in this white paper goes beyond the interconnection to include site preparation and the electrical and civil work required to site storage and EV charging by third party suppliers.

For energy storage, the Company will enable third-party developers to dock their equipment and interconnect at designated interconnection point(s). This will be achieved through the extension and upgrade of the electrical distribution system to the property. The Company anticipates that third party developers will own and operate their energy storage equipment at this site. The Company will explore new and innovative models to enable siting of storage on this property including storage's capacity, wholesale energy or distribution system value and reliability needs. The Company anticipates that third party developers will completely design, own and operate their energy storage equipment at this site. In the event that third-parties cannot provide a cost-effective solution within pre-established project timelines, the Company may pursue procuring and installation of the storage equipment on these docking stations. Site infrastructure development is estimated to cost a total of $15M, with $10M spent during the upcoming rate period.

[1] Case 18-E-0130, In the Matter of Energy Storage Deployment Program, Press Release – Governor Cuomo Announces New York Energy Storage Roadmap to Achieve Nation-Leading Target of 1,500 Megawatts by 2025 to Combat Climate Change, released June 21, 2018.

The make-ready interconnection site preparation will entail:

- Establishing security barriers/fence to restrict access to critical ES infrastructure;
- Extending the distribution system and providing standardized interconnection equipment;
- Remediating the land (if applicable); and
- Ensuring a flat topography with adequate drainage to ease developers installing the battery storage equipment.

For EV's, the Company will install make-ready infrastructure for customers/developers requesting the interconnection of publicly accessible fast chargers which will support EV adoption in Con Edison's territory. Developers when seeking to install EV facilities beyond the point of common coupling typically are required to get a second service for the charging facilities and are characterized as excess distribution facilities (EDFs). By using the distribution system that will already be in place for ES, developers will no longer face this hurdle and can benefit from the existing systems.

The proposed system of distribution service is a 460V Spot Network, supplied by five 27kV network feeders from the (1B) Borough Hall network. This system was selected for its reliability, cost advantage, and minimal real estate footprint requirements when compared to other options. The design will be a standard N-2 system in order to provide network level service reliability to the battery site, scalable up to 10MWs. An N-2 system provides the most flexibility with the ability to charge and discharge even in the event of an outage on any two network feeders. The 460V Spot Network service will require five network feeders and five 2500kVA transformers with associated bus work and network protectors. The feeders were selected considering proximity, loading, reliability, and optimal bus diversity.

Justification:

Energy Storage

The Company identified the Nevins Street property as conducive for third party developers to site their storage equipment. The Company intends to permit developers who are interested in pursuing bulk-system capacity payments, energy arbitrage or other market revenue streams to interconnect to the distribution system at these sites, subject to the Company's applicable operational, safety and security rules. The Company will provide a turn-key interconnection site, which will reduce risk to the third-party developer's investment by providing greater certainty about land-development and interconnection costs.

Electric Vehicles

Con Edison's dense urban service territory presents a unique challenge for deploying EV infrastructure. Public fast charging is viewed as a necessary component of the EV charging ecosystem for dense urban environments, as many vehicle owners do not have access to dedicated parking in driveways and rely on street or public charging. By taking a proactive approach to promoting and preparing for increased EV adoption including through co-locating charging facilities with other resources such as storage, Con Edison is both addressing stakeholder needs for EV charging infrastructure planning and development and testing innovative methods that can provide early lessons to the Company in the management of a more dynamic grid.

The Company intends to use funds from the REV Demonstration projects focused on EVs to develop deeper insights into the costs associated with electrical and civil work behind the meter to enable the deployment of the actual chargers that would be owned and operated by third party developers. Since the

Company owns the property, soft costs associated with site host negotiations for easements and right-of-ways will be avoided which should allow for a more streamlined development.

Colocation of Storage with EVs
As EVs gain traction going forward, the colocation of storage with EVs may help provide the Company with useful early learnings about whether there are economic or technical storage use cases that can help offset spikes in demand due to increased transportation electrification that may otherwise result in the need for new utility infrastructure upgrades or load relief

Supplemental Information:

- Alternatives:
  Dependence on market development of BTM customer owned and operated energy storage system. However, with the large footprint required by batteries and the space and permitting constraints in the New York City area, this model can be expected to result in barriers to entry. EV Chargers can be sited on private property. However, leveraging the civil and interconnection work with ES project reduces the need for interconnection studies and additional upgrades necessary for grid connection.
- Risk of No Action:
  Taking no action would delay testing of new and innovative methods to increase storage in New York and further leave Con Edison unprepared or underprepared in developing a better understanding of the impact and management of new technologies such as storage and EVs on the grid.
  It reinforces the status quo and would hamper achievement of state policy goals, delays benefits from a beneficial technology, and impede meeting clean energy and ZEV mandates.

- Non-financial Benefits:
  By building an Energy Storage portfolio, an easier path is facilitated for greater penetration of renewables, DERs, and ultimately achieving state policy goals. The EV program is expected to increase customer satisfaction for those who own EVs or who develop EV charging infrastructure. Also, by enabling the fuel conversion of vehicles from combustion engines to electric vehicles, GHG and sulfur and nitrogen oxide (SOx and NOx) emissions will be reduced. Furthermore, co-locating with storage will help provide useful early learnings about whether there are technical use cases that can help offset spike is demand due to increase transportation electrification, which may otherwise result in need for utility infrastructure upgrades or load relief.

- Summary of Financial Benefits (if applicable) and Costs:
  The EV site preparation will be funded via the Demonstration budget and the costs for interconnection for the storage will be leveraged.

- Technical Evaluation/Analysis:
  The Company experience with the procurement and installation of the BQDM utility-owned battery installation and the coordination and engineering of third party developed projects has provided the Company with technical insights in the evaluation. A team of Company experts surveyed the land and performed tests to determine remediation requirements, ease of construction, best route of electric infrastructure and sizing of ES and EV system based on specifications to establish maximum potential.

- Project Relationships (if applicable):
  Utility Owned Energy Storage - The Company proposes to develop six Company-owned sites totaling 31.5MW to install energy storage equipment to evaluate and study the beneficial uses of such equipment for the distribution system. The 31.5MW of load relief will provide up to 120MWh of energy for discharge and were sized to optimize the land usage as well as the loading requirements.
  REV-Demo Projects - Con Edison aims to explore energy storage technologies and associated new business models which increasingly have the potential to support cost-effective solutions for distribution-level grid needs.
  EV targeted initiatives in various stages of development or implementation that focus on supporting DC fast charging, access to curbside fast charging, incenting EVs to charge during off-peak hours, and introduction of electric school buses that can also act as grid support assets.

- Basis for Estimate:
  The order of magnitude cost storage estimates for the make-ready site is based on a standard N-2 design, 2020 forecasted load and in-service date, charging time and up to 10MW's of storage potential. Each year's costs use the overnight capital cost from the same year (not the start year), overhead rate and contingency factors.

Total Funding Level ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	252	252	253	-	-
M&S	4,200	4,200	4,200	-	-
A/P	-	-	-	-	-
Other	371	373	373	-	-
Overheads	177	175	174	-	-
Total	**5,000**	**5,000**	**5,000**	**-**	**-**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Non-Network Feeder Relief (Open Wire)
Project Manager	Not Applied
Hyperion Project Number	PR.5ED0091, PR.5ED4101, PR.5ED1121, PR.5ED3111, PR.5ED2101
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
The goal of this project is to provide relief for non-network feeders (4kV feeders) that are projected to operate at greater than 100% of their normal (all equipment in service) ratings and 100% of their contingency rating (N-1). Relief projects include replacing overloaded cable with higher rated cable, transferring load from one feeder to another feeder, or establishing new feeders. Each year the Company plans to replace approximately 95 poles, 190 spans of overhead wire, 200 feet of conduit, 4 primary risers, 4 air switches, and 20 sections of underground cable. The program will address the projected overloads in priority order. The Company's goal is to annually relieve all high priority feeder overloads prior to the start of summer.

In order to address overload conditions of non-network feeders, a number of methods may be implemented. The first method involves replacing existing cable with cable of greater capacity. A second method involves rearranging feeders to transfer load. This includes dropping off portions of a feeder to adjacent feeders that have the capacity to handle additional load. A third method is to create new 4 kV feeders or step-down feeders as per *EO-2091 'System Design for Relief of 4 kV Load Areas using 2500 kVA Step-Down Transformers'*. The method chosen for each specific overload is determined using engineering cost-benefit analysis.

Justification Summary:
As system load grows, individual feeders may exceed their design limits. Feeder peak loads and calculated feeder ratings are used to determine if a feeder needs reinforcement. The process for rating a feeder is specified in *EO-2048 'Determination of Distribution Feeder Ratings 60 Cycle Systems'*. If the projected feeder load for the "in-service year" is greater than the feeder rating for that year, then reinforcement of the feeder is required. According to *EO-2072 'Method Of Planning Reinforcement Of Network and Radial Feeders Operating at 13, 27 & 33 kV'*, when an overload is determined, plans for eliminating the overload must provide a reasonable margin to cover three years (the next in-service year, and two years into the future). Reinforcement plans generally call for eliminating small size cables, establishing new feeders, or transferring load by rearranging feeders. With an increase in wire and equipment size, existing poles and fixtures may not have the capability to support additional weight and may require replacement as well. In some cases, our feeders have reached full capacity with all other relief options having been exhausted and the only way to de-load is to create a new feeder.

<u>Supplemental Information</u>:

- <u>Alternatives</u>:
  Continue to operate under current conditions and risk failure of overhead wires which can cause accelerated failures and potential customer outages.

- <u>Risk of No Action</u>:
  All System Expansion projects will be reviewed for Non Wires Solution in accordance with the suitability criteria outlined in the DSP

  The overloaded overhead wires can possibly fail and cause outages if not addressed proactively by the Company.

  If we exceed the number of allowable times the use of emergency ampacity occurs we will be forced to load shed. Use of emergency ampacity occurs when a cable is loaded above its normal 24 hour contingency rating without exceeding its temperature limitations. As per *EO-6041 'Standard Ampacity Ratings For 4 KV Primary And Low Voltage Secondary Mains Cables Installed Overhead And In Riser Pipes',* emergency ratings "are applicable for an average, over several years, of one period of not more than thirty six hours per year, but for a total of not more than three periods in any twelve consecutive months".

- <u>Non-financial Benefits</u>:
  Non-network feeder relief reduces the risk of non-network feeder failures. This minimizes potential safety risks, reduces customer outages and improves the overall reliability and resiliency of the overhead system.

- <u>Summary of Financial Benefits (if applicable) and Costs</u>:
  Non-network feeder reinforcement increases the reliability of the feeder and reduces potential feeder outages. As a result, potential regulatory penalties associated with SAIFI and CAIDI can be minimized.

- <u>Technical Evaluation/Analysis</u>:
  The following Con Edison specifications are used when evaluating feeder loading and relief requirements:
  - EO-2048 Determination of Distribution Feeder Ratings 60 Cycle Systems
  - EO-2072 Method of Planning Reinforcement of Network and Radial Feeders Operating at 13, 27 & 33 kV
  - EO-6041 Standard Ampacity Ratings for 4 kV Primary and Low Voltage Secondary Mains Cables Installed Overhead and in Riser Pipes

- <u>Project Relationships (if applicable)</u>:

- <u>Basis for Estimate</u>:
  The estimate is based on historic unit costs prorated to account for increasing costs over the next five years.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	882	669	261	905		545
M&S	473	216	130	368		282
A/P	519	213	518	1,457		2,719
Other	(26)	22	40	34		32
Overheads	1,009	796	397	1,045		1,026
Total	**2,857**	**1,916**	**1,346**	**3,809**		**4,604**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	676	1,635	1,635	1,635	1,635
M&S	304	736	736	736	736
A/P	1,124	2,719	2,719	2,719	2,719
Other	21	51	51	51	51
Overheads	885	2,141	2,141	2,141	2,141
Total	**3,011**	**7,283**	**7,283**	**7,283**	**7,283**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Overhead Transformer Relief
Project Manager	Various
Hyperion Project Number	PR.9ED0281, PR.9ED4081, PR.9ED1931, PR.9ED3811, PR.4ED2111
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program addresses overhead transformer overloads. Overhead transformers are field inspected and those determined to be overloaded, are replaced prior to the summer and heat events that pose the greatest potential for units to trip. The anticipated number of transformer replacement per region is shown below:

- Units per Year: Staten Island 31 units, Brooklyn/Queens 40 units and Bronx/Westchester 31 units.

Justification Summary:
Overhead transformers are operated according to specification EO-2000. Our current process identifies potentially overloaded transformers before the peak summer period, and designs jobs to relieve those transformers. The goal of this program is to reduce the potential number of overhead transformer trips that result in customer outages and to protect our transformers from damage caused by overheating. An additional benefit to this load relief is the available capacity the new transformers provide that supports neighboring circuits in the event of a loss of a transformer and the need to supply customers on a temporary basis. In addition to loading studies done on overhead transformers, an annual review of all customer outages with a Completely Self Protected (CSP) transformer trip or customer complaints of an overhead transformer oil leak is completed. If the root cause is determined to be an overloaded/overheated transformer, the transformer is added to the list of overhead transformers requiring relief/replacement.

Supplemental Information:

- Alternatives:
  All System Expansion projects will be reviewed for Non Wires Solution in accordance with the suitability criteria outlined in the DSP

  One alternative is to institute customer demand reduction for any identified overloaded transformer. Customer participation would be critical for this alternative to be successful in helping to avoid future CSP trips or overheating/overloading conditions. A second alternative would be to operate the equipment until failure. When a failure occurred, customer outages would also occur. Customer restoration times would be dependent upon the number of these events occurring simultaneously and the availability of the troubleshooter work force to respond. Neither alternative provides a sound solution for addressing overloaded transformer equipment. In one case action would be required only from a very specific number of customers downstream of the overloaded transformer. In the second case, a number of coincident transformer failures during peak loading conditions would lead to extended outages to customers as crew availability became an issue.

- Risk of No Action: When overloaded, transformers overheat. This presents a greater potential for oil leaks to develop, damaging equipment and creating a significant environmental concern. Operating these transformers until failure will have a negative impact on customer reliability and satisfaction, and greatly increase the likelihood of customer outages.

- Non-financial Benefits: This program minimizes a potential safety risk to the public, lowers the number of oil spills into the environment, has a positive impact on customer satisfaction, reduces customer outage frequency, and improves the reliability of the overhead secondary system.

- Summary of Financial Benefits and Costs: N/A

- Technical Evaluation/Analysis: Many of our overhead transformers are Completely Self Protected (CSP) meaning that when they are initially overloaded, they will automatically trip. This is referred to as a 'CSP' trip. When crews respond, they can reset these units or set to Emergency/Lock-in position.

  We are currently using a computer application called Load Aggregator. This program combines our secondary mapping data and our customer service information billing data to proactively identify and prioritize transformers that have the greatest potential to trip, based upon customer summer load readings.

  The CSP trip feature is advantageous to our system because it protects transformers from overheating damage. When a CSP trip occurs, it takes the transformer out of service and any customers connected to it lose electric service.

- Project Relationships (if applicable): N/A

- Basis for Estimate: Historic unit costs were used.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	711	561	686	784		604
M&S	185	118	188	135		45
A/P	241	292	353	404		165
Other	1	0	0	-3		8
Overheads	767	668	639	631		405
Total	**1,905**	**1,639**	**1,866**	**1,951**		**1,227**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	525	566	608	595	611
M&S	301	379	396	373	336
A/P	256	289	242	281	229
Other	386	429	450	428	430
Overheads	753	636	602	623	694
Total	**2,221**	**2,299**	**2,299**	**2,299**	**2,299**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Primary Feeder Relief
Project Manager	Various
Hyperion Project Number	PR.5ED0011, PR.5ED1041, PR.5ED3021, PR.5ED4011, PR.5ED7011
Status of Project	In progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program funds reinforcement (load relief) work on primary distribution feeders that have been projected to operate above their thermal ratings during the summer peak load period. This applies to both normal/continuous (all equipment in service) and contingency/emergency (up to two network/load-area feeders out of service) conditions. Reinforcement projects may include cable replacement, transferring load between feeders, balancing load on a given feeder, bifurcating an existing feeder, and establishing new feeders.

Each year the distribution system is evaluated for load relief to determine specific system reinforcement needs based on the Area Substation and Sub-Transmission Feeder Ten-Year Load Relief program. These studies incorporate recent summer peak load data with location-specific information about customer growth and projected demand forecasts. They also factor in any new construction expected to be in-service that year. The primary feeder relief plan is then developed after every network's primary feeder capacity has been reviewed, based upon both the previous summer's loading and the upcoming summer forecasted load. This review occurs annually.

The primary feeder relief program is focused on proactively reinforcing distribution feeders that are projected to be overloaded during the upcoming summer peak periods.

- **Mandatory:**
  Con Edison specifies that all feeders operate at, or below, 100 percent of their thermal rating. This is maintained by relieving all cable sections that are operating above 100 percent of rating.

  Operating specification EO-2072 illustrates how to determine the need for network feeder reinforcement, and plan and schedule reinforcement work for completion as required. The sections of this specification relating to load information, such as load readings and load growth, apply to all types of distribution feeders.

- **High-level schedule:**
  Primary feeder relief is conducted on an annual basis. Each fall the feeders are modeled using the Poly Voltage Load Flow (PVL) program, which is updated to include the prior summer's peak load data. All feeders with projected overloads have projects designed to ensure the feeder operates below its maximum capacity. All of these projects are scheduled and completed prior to May 31 of the following year.

<u>Justification Summary</u>:
Per our specifications, distribution feeders must operate within their design thermal capabilities for both normal/continuous and contingency/emergency operation. Primary Feeder Relief ensures that the feeders are operating within their thermal capabilities

Primary Feeder Relief is an annual relief program to maintain and ensure capacity on all primary distribution feeders. Adequate feeder capacity ensures the reliability of both the Company's primary and secondary distribution systems, and provides our customers with highly reliable service.

<u>Supplemental Information</u>:

- <u>Alternatives</u>:
  All System Expansion projects will be reviewed for Non Wires Solution in accordance with the suitability criteria outlined in the DSP

- <u>Risk of No Action</u>:
  Taking no action would allow feeders to operate above their thermal ratings for extended periods of time. This could compromise the integrity of the primary cable insulation and make primary feeders more prone to failure.

- <u>Non-financial Benefits</u>:
  Primary feeder reinforcement often targets the removal of overloaded PILC cable from the system. The PILC cable contains lead and dielectric oil that could contaminate the environment. The removal of PILC cable sections and their associated stop-joints also enhances network reliability as measured through the NRI (Network Reliability Index).

- <u>Summary of Financial Benefits (if applicable) and Costs</u>:
  This is an operationally required program. By specification, the Company does not permit distribution feeders to operate beyond their thermal ratings.
  Primary feeder reinforcement increases network reliability and reduces the risk of a network shutdown. The risk of a network shutdown and the associated costs, including restoration costs and PSC's network shutdown penalty, are significantly reduced through the Primary Feeder Reinforcement program.

- <u>Technical Evaluation/Analysis</u>: Primary feeders are evaluated annually for normal and emergency capacity using the Company's Poly Voltage Load Flow Program (PVL).

- <u>Project Relationships (if applicable)</u>:
  PILC Cable Removal

- <u>Basis for Estimate</u>: Historic unit costs

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,553	917	566	418		618
M&S	1,122	419	213	498		363
A/P	826	689	169	526		339
Other	19	255	416	429		420
Overheads	2,356	1,910	829	842		801
Total	**5,876**	**4,190**	**2,193**	**2,713**		**2,541**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	959	2,521	2,521	2,504	2,504
M&S	616	1,619	1,619	1,387	1,387
A/P	601	1,579	1,579	1,332	1,332
Other	363	953	953	387	387
Overheads	1,587	4,172	4,172	4,834	4,834
Total	**4,126**	**10,844**	**10,844**	**10,444**	**10,444**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Ed Koch Queensboro Bridge 13kV Riser Replacement
Project Manager	Albert Wang
Hyperion Project Number	PR.23441915
Status of Project	Initiation
Estimated Start Date	January 1st, 2019
Estimated Completion Date	December 31st, 2023
Work Plan Category	Operationally Required

Work Description:
The purpose of this project is to replace the 13kV distribution riser cables that route over the Ed Koch Queensboro Bridge, also known as the 59th Street Bridge that supplies electric power to Roosevelt Island. The existing riser cables consist of aerial paper cables supported by the bridge pier structures and on messenger wires above the North and South Outer Roadways (see Figure 1). There are a total of twelve riser cables that will be replaced, six on the Manhattan pier structure and six on the western Roosevelt Island pier structure.

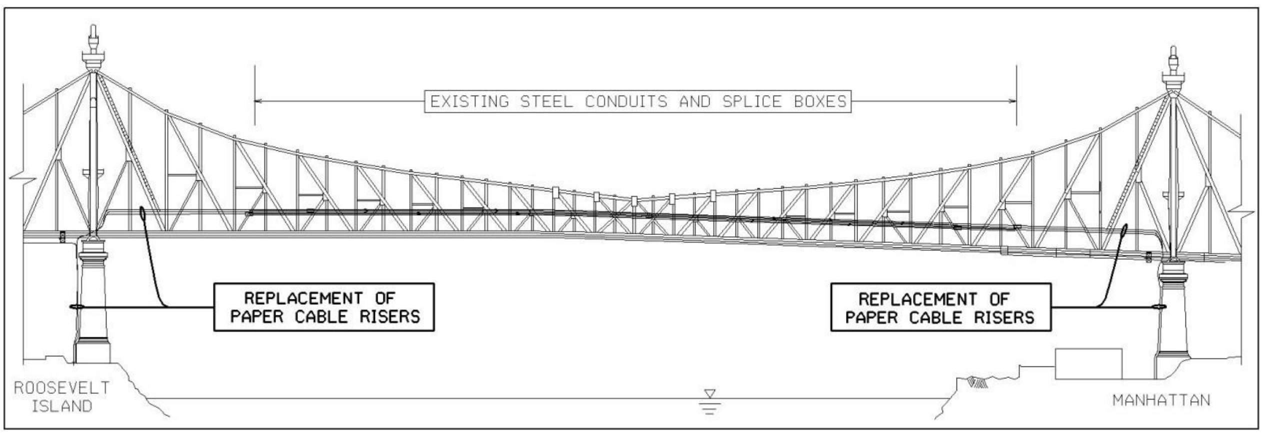


Figure 1: Ed Koch Queensboro Bridge North Elevation

High-level schedule:

Planning and design work on the distribution riser replacement will begin in 2019. Con Edison will retain engineering consulting services to complete initial and detailed designs for the riser replacement and cable pull setup. Based on the detailed design and construction bid-package, Con Edison will engage an external construction vendor and establish an agreement to complete this non-routine work, inclusive of installing all necessary supports and cables. Construction activities will begin in 2021 and last through 2022. Con Edison will perform any associated splicing work in parallel to allow proper construction sequencing to facilitate replacement work. The new risers will be completed and commissioned prior to the end of 2023 (see Figure 2).

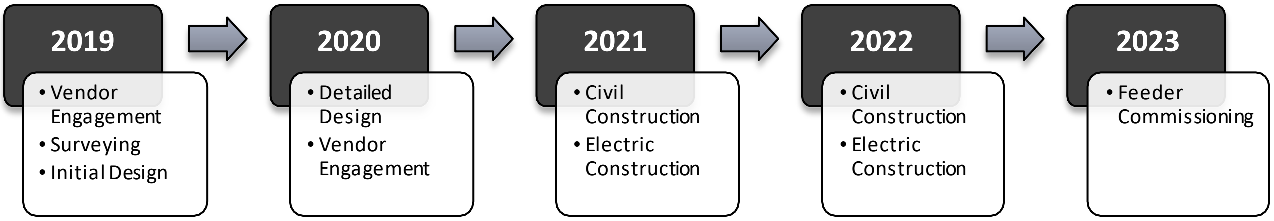


Figure 2: High-Level Project Schedule

Justification Summary:

Since 2004, there have been fifteen failures and emergency repairs of the distribution cables on the bridge. With such a high rate of failure, the feeders presented public safety and electric reliability concerns. To address these concerns, from 2012 through 2017, Electric Operations designed and executed the '59th Street Bridge Crossing' project (Project No. Z13-06880-M) to upgrade the infrastructure supplying Roosevelt Island.

The project scope included the replacement of the existing messenger wires and aerial paper feeder cables on the main bridge spans with new conduit systems, consisting of structural steel support brackets, 5 inch steel conduits, and splice box enclosures. The new systems were equipped with 3-750 EPR-NL feeder cables. In addition, the project design included the installation of new armored cable risers on the bridge piers and the subsequent retirement of the existing risers.

During construction, the field conditions and the rigidity of the armored cables prevented them from being installed through the multiple bends of the bridge. Pulling calculations confirmed that the armored cable route was not constructible and the armored cables would not be able to be manipulated into the route as provided in the design. Therefore, a revised concept was implemented which connected the newly installed conduit systems and associated EPR-NL cables on the bridge spans to the existing riser cables. The replacement of the risers was deferred to allow for a detailed review and redesign of the riser portion of the project.

Supplemental Information:

- Alternatives:

All System Expansion projects will be reviewed for Non Wires Solution in accordance with the suitability criteria outlined in the DSP

Multiple alternative options were reviewed during the planning of the original '59th Street Bridge Crossing' project. These included, (i) placing the conduits under the bridge, (ii) replacing the existing messenger cable system like-in-kind, and (iii) exploring the possibility of feeding Roosevelt Island from a network from the Queens' distribution system using a directional boring method under the river.

Each alternative option was evaluated on a number of different factors including the likelihood of the plan being approved by the New York City Department of Transportation (NYCDOT), the expected cost, the degree of protection for the feeder cables, and general feasibility. While each option was viewed favorably in one or more of the factors, they also had significant disadvantages. The selected design of replacing the existing aerial messenger system with a new conduit system was favorable across all of the factors.

This project, which will focus solely on the replacement of the twelve existing riser cables, will also be evaluated to ensure the most optimal solution is implemented. LiDAR and 3D modeling will be utilized to determine an ideal route from the top of the pier structure, through the bridge infrastructure, to above the outer roadways. Cable pull calculations will be a critical tool in the analysis of any proposed route. The calculations will have two main purposes, first, to ensure that the route does not exceed the physical limitations of the cable, and second, to help determine suitable means and methods for installation.

- Risk of No Action:
  The existing risers are predominately comprised of older paper cables and have had fifteen failures and emergency repairs since 2004. There is a concern that these aged cables will begin failing at an increased rate, affecting the safety of pedestrians, cyclists, and vehicles, and jeopardizing the reliability of the electric service to Roosevelt Island. Cable failures may result in cascading feeder failures, which could result in a significant number of customers experiencing an extended outage. This problem will be exacerbated as the cables continue to age and become more prone to failure over time. In addition, the risers, due to their smaller cable size, limit the overall capacity of the feeders, constraining the future growth of Roosevelt Island.

- Non-financial Benefits:
  This project will help prevent a large customer outage on Roosevelt Island. In addition, removing the older paper cables and messenger wires above portions of the North and South Outer roadways will increase the resiliency of the system, improving the safety for pedestrians, cyclists, and vehicles on the bridge.

- Financial Benefits and Costs:
  Proactively replacing the riser cables towards the end of their useful life allows for proper construction sequencing and ensuring an optimal plan is implemented rather than a “quick-fix”. In addition, replacing the risers with larger cables will provide Roosevelt Island substantial electric capacity for its developing landscape.

- Technical Evaluation/Analysis:
  The Ed Koch Queensboro Bridge is under the jurisdiction of the NYCDOT Division of Bridges. The NYCDOT requires that any major work or modification to the bridge be performed by qualified engineering firms. As such, Con Edison will need to contract a third-party engineer who meets all the requirements of the NYCDOT. Due to the unique location of the work, many different variables will be taken into consideration during the design and planning phase. This includes, but is not limited to, work area access and egress, equipment access, marine rescue and emergency egress, allowable bridge member support loads, global and local roadway loading, roadway envelope limitations, expansion, deflection, and vibration concerns, future inspection and maintenance requirements, suitable staging locations, temporary structures and scaffolding, and temporary protection of existing facilities.

  In addition, the area underneath the bridge, specifically between the anchor pier and adjacent pier structure in Manhattan and Roosevelt Island, falls under the jurisdiction of several city agencies. This includes the NYCDOT Office of Construction Mitigation and Coordination (OCMC), NYCDOT Division of Bridges, and the Roosevelt Island Operating Corporation (RIOC). Any major work scope requiring the erection of scaffolding to facilitate inspection or installation activities will require close coordination and communication between Company and Contractor representatives and the various city agencies responsible for providing construction and permit approvals.

  Special consideration will be given to ensure all that proposed work activities can be safely performed within the expected stipulations for closures of the North and South Outer Roadways. Recent permits issued by the NYCDOT for full closures of the outer roadways have had very limited work hours, typically 9 p.m. to 5 a.m. nightly. The NYCDOT has also required the permit holder to operate a sizable shuttle bus service for pedestrians and bicyclists during any closure of the North Outer Roadway. The most recent permit required that the shuttle system be capable of transporting 80 passengers and 65 bicycles every 15 minutes from pick-up and drop-off points in both Manhattan and Queens.

- Basis for Estimate:

  The order of magnitude estimate for this project was based on recent costs for work performed on and around the Ed Koch Queensboro Bridge. In addition, historical Work Management System reports and unit costs for subsurface digging, the installation of conduits, structures, cables, as well as splicing and associated work were utilized.

- Project Status:

  Initiating – The project is in an initiation phase to determine the overall scope and design options.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	53	124	839	432	142
A/P	374	877	5,973	3,038	1,004
Other	38	88	599	305	101
Overheads	285	510	3,188	1,725	554
Total	**750**	**1,600**	**10,600**	**5,500**	**1,800**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Secondary Mains Load Relief
Project Manager	Various
Hyperion Project Number	PR.5ED0071, PR.5ED7071
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program funds work as per Company guidelines on secondary mains whose loading is projected to exceed loading capability based on the forecasted system electric load growth and customer expectations including emergency response. Secondary mains replacements are prioritized based primarily on loading, voltage issues, past performance, age, conductor size and conductor type. Additional analysis factored into the prioritization of reinforcement projects includes impact to system performance including System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI) and Network Reliability Index (NRI).

High-level schedule:
Based on historical trends, the following schedule is an estimate based current plans:

Type (unit)	2019	2020	2021	2022
UG Conduit (trench feet)	1,107	972	2637	2560
UG Structures (number)	10	8	23	22
UG Cable (sections)	66	58	158	153

Justification Summary:
The Con Edison electric distribution system is designed to operate safely and reliably under the 1st (non-network) and/or 2nd Contingency (network) standards in each of the respective regions without system component failure. These Company design standards require annual studies of electric network distribution system models that would enable identification of locations to be considered an overload or under voltage. As per the operation guideline EOP-5314: ED-1 BUDGET PRIORITIZATION for the secondary low voltage distribution network grid of cables, load relief work on underground AC low-voltage mains and services should be initiated for reported overloads that are greater than or equal 125% of that set of mains' or services' first or second contingency thermal ampacity rating as per EO-6039: Standard Ampacity Ratings For 600 Volt Ac Underground Service Cables In Ducts, And Service Take-Offs Form Multi-Bank Transformer Installations and EO-6040: Standard Ampacity Ratings for 600 Volt AC Mains Cables Installed Underground in Ducts as stated in Bulletin B-207. This percentage is based on results from the Low-Voltage Cable Thermal Capability project and helps operations and planning prioritize work. An additional benefit from this program, along with other secondary reliability programs, is to reduce the risk of stray voltage caused by defective cable, manhole events, and customer outages as well.

Relief projects include replacing the overloaded secondary cable sections with a new secondary cable of higher rating, installing additional secondary cable sections in order to decrease the load on the sections to a level where it is no longer overloaded, and to install transformers in order to take load off of the secondary grid and mains. Existing vacant secondary ducts would be utilized for the installation of additional secondary cable sections if available. In certain cases, additional structures may be installed or existing ones enlarged to accommodate the additional secondary cable. Secondary ducts will also be installed when insufficient vacant exist.

Supplemental Information:

- Alternatives:
  All System Expansion projects will be reviewed for Non Wires Solution in accordance with the suitability criteria outlined in the DSP

- Risk of No Action:
  Taking no action poses significant safety and reliability concerns. Secondary mains that operate at or over their design temperature for extended periods of time are susceptible to degradation as per their manufacturer specification. This can lead to premature failure or stray voltage, creating an additional burden on the connecting secondary mains and nearby transformers. The failure of the secondary section can lead to smoking manholes, manhole fires, manhole explosions, secondary burnouts, carbon monoxide (CO) events, and customer outages.

  Manpower constraints are created when responding to these outages, especially during winter storms as well as peak summer load periods. In addition, other secondary cables are subject to higher loads, which can impact their expected life when overloaded secondary cables do fail.

- Non-financial Benefits:
  The program is crucial to enhancing the safety, reliability and strength of the secondary voltage grid by reinforcing overloaded areas and preventing secondary cable failures. This work would also mitigate public and employee safety risks.

- Summary of Financial Benefits (if applicable) and Costs:
  For network secondary work, the analysis of all Con Edison system networks may yield results to reinforce certain areas of the grid. Targeted and proactive replacement of overloaded mains would reduce the possibility of manhole events, and the need to replace all mains that enter and exit the structure. Proactive main replacement costs are approximately $28,000 for a single main. With an average of eight mains in a structure, replacement of mains after a catastrophic event is estimated to cost $224,000.

- Technical Evaluation/Analysis:
  As per Company specifications EOP-5303: SECONDARY DISTRIBUTION SYSTEM ANALYSIS, EOP-5319: PREPARATION FOR REINFORCEMENT PROJECTS OF PRIMARY AND SECONDARY SYSTEMS, and EOP-5314, Engineering teams throughout the Regions will use the Company's load flow (PVL) program to determine which secondary mains, if necessary, may need to be relieved. Customer billing data and network distribution transformer data is used to estimate peak demand at each service point. The network connectivity model with secondary, primary, and substation connections would provide an accurate representation of the network's components and related attributes and electric characteristics. PVL would be used to compute the flow on each secondary main for all possible contingencies of the primary feeders supplying the network, and provide reports of any overloads. Relieving secondary mains that are

projected to be at and above 125% of the normal rating and contingency ratings will ensure the safety and reliability of the secondary network grid as per Company requirements.

- Project Relationships (if applicable):
  Underground Secondary Reliability; Secondary Open Mains

- Basis for Estimate:
  Historical unit cost data.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	126	124	814	1,007		150
M&S	71	8	376	568		29
A/P	106	21	651	1,362		30
Other	2	1	5	11		-
Overheads	245	135	1,134	1,492		109
Total	**550**	**289**	**2,980**	**4,440**		**318**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	496	376	822	1,483	1,536
M&S	678	620	1,402	2,125	2,096
A/P	275	541	2,183	681	667
Other	567	323	782	1,077	1,029
Overheads	869	669	1,875	1,698	1,736
Total	**2,885**	**2,529**	**7,064**	**7,064**	**7,064**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Yorkville Crossings and Feeder Relief
Project Manager	Manhattan Project Management
Hyperion Project Number	PR.21479860
Status of Project	In Progress
Estimated Start Date	January 1st, 2017
Estimated Completion Date	June 1st, 2021
Work Plan Category	Operationally Required

Work Description:
To maintain the reliability of the Yorkville network, a new underwater crossing beneath the Harlem River between Manhattan and the Bronx will be established and the existing 13 kV primary feeders will be diversified.

The Yorkville network, located in Manhattan, is supplied from twenty-nine (29) 13 kV distribution feeders that emanate from the Hell Gate Area Substation located in the Bronx. The boundaries of the Yorkville network are 110th Street to the north, 77th Street to the south, 5th Avenue to the west, and the East River to the east (see Figure 2).

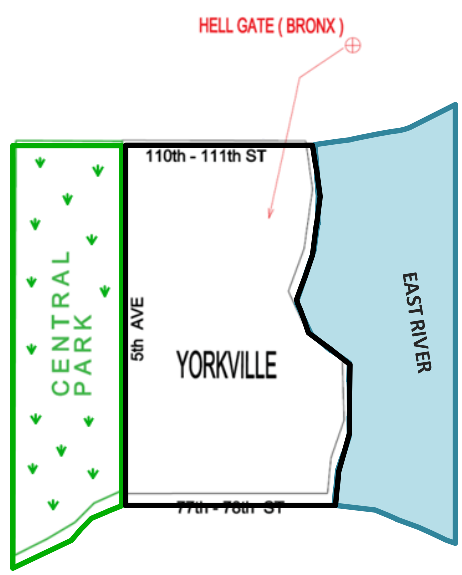


Figure 2: Existing Boundaries of the Yorkville Network in Manhattan, New York

The distribution feeders reach Manhattan via six (6) active underwater crossings. Four (4) of these crossings span across the Harlem River near the Willis Avenue and Third Avenue Bridges, known as Crossings Nos. 80, 81, 83, and 84 (see Figure 3). These crossings contain twenty-three (23) of the twenty-nine (29) feeders that supply the Yorkville network.

The fifth and sixth crossings route the distribution feeders via Randall's Island, known as Crossings Nos. 82 and 85. These crossings contain the remaining six (6) primary feeders that supply the Yorkville network as well as the distribution feeders that supply the Randall's Island network.

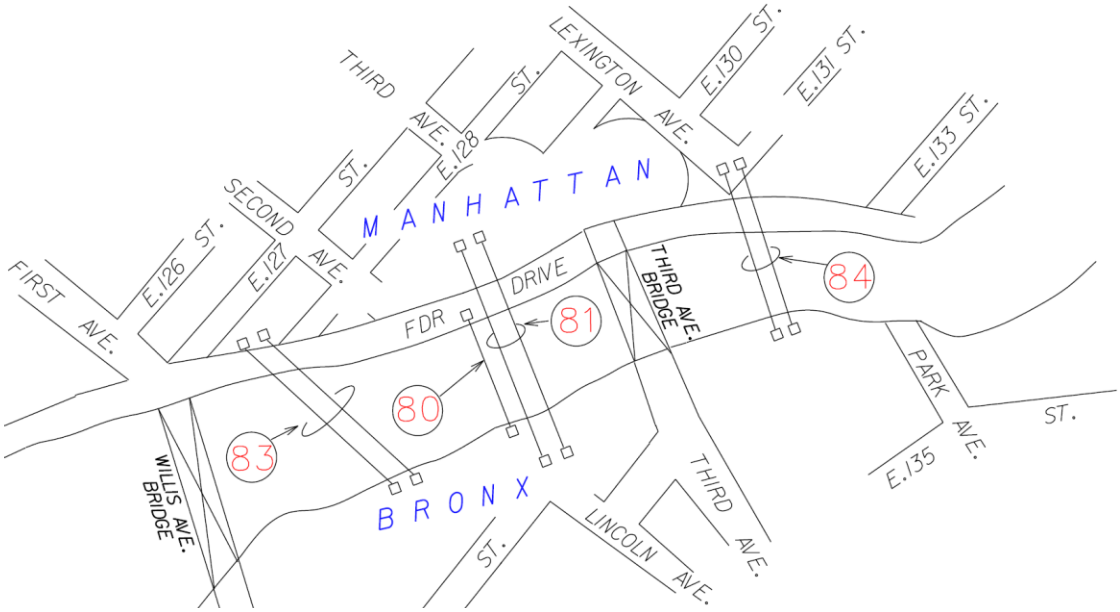


Figure 3: Underwater Crossings between Manhattan and the Bronx (Labeled Crossing Nos. 80, 81, 83, and 84)

The new underwater crossing will be comprised of a bundle of seven (7) 6-5/8" High Density Polyethylene (HDPE) conduits, similar to the composition of the existing crossings. The new crossing will be constructed under the base of the river by means of horizontal directional drilling (HDD), micro tunneling, or a suitable alternative, depending on the exact geological and subsurface conditions. New terminal manholes and new outlet systems will be constructed on either side of the Harlem River so that the new crossing can interconnect with the existing distribution system. Each of the conduits will be equipped with 3-750 kcmil EPR-NL primary feeder cables.

High-level schedule:

Planning and design work on the New Harlem River Crossing began in 2017 and 2018. Con Edison will retain engineering consulting services to complete a detailed design of the underwater crossing and cable pull setup. Based on this detailed design, Con Edison will engage a construction vendor and establish an agreement to complete this non-routine work, inclusive of building the crossing and pulling the cables. Construction activities for the crossing will begin in 2019 and last until 2020. Conjunctional Con Edison construction work on the outlet systems and distribution feeder rearrangement will be in tandem with the vendor work. The new system will be completed and commissioned prior to the summer of 2021 (see Figure 4).

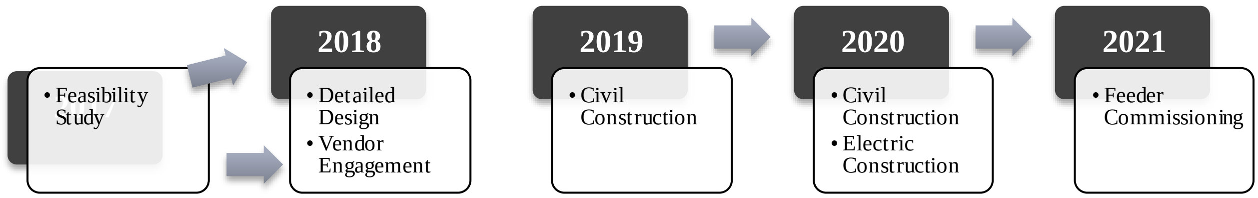


Figure 4: High-Level Project Schedule

Justification Summary:

The four (4) underwater crossings that span between Manhattan and the Bronx all have high duct occupancy and few remaining spare conduits as shown in Table 1. These spare conduits are critical in maintaining the reliability of the Yorkville network for both accommodating future load growth and for cable replacements due to failures. Many of the feeders are already double-legged (i.e. one feeder with two legs from the same station circuit breaker), with each leg having their own conduit, to support the high load of the Yorkville network.

Table 1: Underwater Crossings Showing Duct Occupancy and Spares

Crossing 80
48" Aband. Gas Main
3M43L
3M43M
3M49L
3M49M
Obstructed
Obstructed

Crossing 81-North
7-6" Conduits
3M45
3M51L
3M54
3M57
3M65
3M69
SPARE

Crossing 83-North
4-6" Conduits
3M53
3M56L
3M56M
SPARE

Crossing 84-North
7-6" Conduits
3M47
3M61L
3M61M
3M64
Fiber Optic
SPARE
SPARE

Crossing 81-South
7-6" Conduits
3M41L
3M41M
3M50L
3M50M
3M51M
3M67
Obstructed

Crossing 83-South
7-6" Conduits
3M52L
3M52M
3M58L
3M58M
3M60L
3M60M
SPARE

Crossing 84-South
7-6" Conduits
3M40L
3M40M
3M55
3M66L
3M66M
3M68
SPARE

The susceptibility of having such few spare crossings was recently highlighted by a City of New York Department of Transportation (NYCDOT) project in which the Harlem River Drive roadway was being reconstructed. As part of such project, the NYCDOT was driving piles for the pier supports of the new roadway within feet of the existing underwater crossings. In response to the NYCDOT activities, and the potential risk of damage to the crossings, Con Edison preemptively developed plans that, in the case of an emergency, would reroute and restore the impacted distribution feeders to service. It was evident that with such few spare conduits, restoring the network to normal operation would pose an immense challenge.

The greatest concern revolves around the crossings between the Willis Avenue and Third Avenue Bridges, Crossing Nos. 80, 81, and 83. Crossing No. 80 currently has no spare conduits, Crossing Nos. 81-North and 81-South have one (1) spare conduit, and Crossing No. 83 has two (2) spare conduits, for a combined total of three (3) spare conduits. These crossings contain sixteen (16) feeders composed of twenty-five (25) feeder legs. With the complete loss of any of these crossings, there are not adequate spares to reroute the distribution feeders and place them back in service without significant temporary reroutes.

In addition to the lack of spare conduits, the majority of the distribution feeders that supply the Yorkville network are heavily-loaded. Based on the 2017-2026 Network Area Forecast, by year 2026, (i) over 85%, or twenty-five (25) of twenty-nine (29), of the distribution feeders will operate at or above 90% of their normal rating, and (ii) 35%, or ten (10) of twenty-nine (29), of the feeders will operate at above 95% of their normal rating as shown in Table 2.

Table 2: Projected Yorkville Load – Ten Year Look Ahead (Summer 2026)

- Loading ≥ 90% - Loading ≥ 95%

Feeder	Normal Load (%)	Emergency Load (%)	Breaker Emergency (Amps)
03M40	**90**	75	828
03M41	**91**	79	906
03M42	81	**90**	659
03M43	**94**	81	968
03M44	88	79	975
03M45	76	61	464
03M46	**90**	83	585
03M47	**96**	82	566
03M48	**96**	81	557
03M49	**91**	89	809
03M50	**92**	**96**	955
03M51	**99**	**92**	1174
03M52	**97**	**97**	476
03M53	**100**	**92**	525
03M54	**96**	**98**	623
03M55	**98**	85	577
03M56	**94**	**95**	740
03M57	**100**	**96**	525
03M58	**94**	87	771
03M60	**90**	86	801
03M61	**94**	79	550
03M62	**90**	81	563

03M63	**99**	**95**	1158
03M64	**99**	84	573
03M65	**93**	**96**	507
03M66	87	73	841
03M67	**93**	87	498
03M68	**93**	**96**	561
03M69	**91**	71	502

The distribution feeder ratings of these heavily-loaded feeders are thermally limited due to high duct occupancy caused by subsurface congestion. In general, the limiting cable sections are those located in and around the crossings, the majority of which are 3-750 EPR-NL cable. In these situations, basketing these cable sections is not a feasible solution as it will increase the duct occupancy on all the adjacent feeders and will exacerbate the issue.

Increasing the feeder diversity, via a new underwater crossing, which is equivalent to increasing the average number of related feeders in the network, is the most effective tool in reducing the feeder pick-up under second contingency conditions.

In addition, under emergency conditions, distribution feeders 03M51 and 03M63 are approaching the station breaker limit of 1200 Amperes, with 1174 and 1158 Amperes, respectively. This project will create capacity in adjacent feeder bands in order to de-load these heavily-loaded distribution feeders.

<u>Supplemental Information</u>:

- <u>Alternatives:</u>
  All System Expansion projects will be reviewed for Non Wires Solution in accordance with the suitability criteria outlined in the DSP

  The design of the Yorkville network, with the supply (Hell Gate Area Substation) located in the Bronx, and the load on the island of Manhattan, presents inherent restrictions in resolving this particular reliability concern. All the distribution feeders that supply the Yorkville network reach Manhattan via underwater crossings and, as such, there are limited options for resolving a lack of spare conduits.

  The alternative to creating a new underwater crossing would be to reduce the loading of the feeders in the existing crossings. By reducing the overall load on the crossings, the load can be consolidated onto fewer cables, making room for spare conduits. To reduce the load, a network load transfer to an adjacent network would need to be performed. As the Yorkville network is geographically bounded by Central Park to the west and the East River to the east (see prior Figure 2), there are limited nearby networks to which to transfer the load. The only destinations would be the Lenox network located to the south or the Triboro network located to the north. The East 75th Street Area Substation that supplies the Lenox network has minimal spare capacity and it would not be able to absorb a network transfer from the Yorkville network. The Parkview Area Substation that supplies the Triboro network has sufficient spare capacity, however, multiple primary feeders would need to be extended multiple city blocks into the footprint of the Yorkville network and portions of the existing primary system of the Triboro network would need to be reinforced. In addition, rearrangement of the Yorkville network feeders would still be required to take advantage of the de-loaded crossings. The expected cost of performing a network load transfer to the Triboro network would be comparable to the cost of a new underwater crossing.

A long term plan would be to establish a new Area Substation in the Upper East Side of Manhattan. By establishing a new area substation, a portion of the Yorkville network could be transferred to the new station, reducing the load on the crossing. Although it is a possible solution, establishing a new area substation is not a financially feasible option when compared to the creation of a new underwater crossing.

- Risk of No Action:
  If no action is taken, cable or crossing failures may result in cascading feeder failures requiring the shutdown of the Yorkville network (relatively low risk) or a significant number of customers may experience an extended outage (low to moderate risk).

- Financial Benefits and Costs:
  Creating a new underwater crossing and diversifying the distribution feeders will reduce the congestion of the existing crossings. Reducing the congestion of the crossing improves the Network Reliability Index value (NRI), and thus the reliability, of the Yorkville network. In addition, having spare conduits under the river allows for the quick replacement due to cable failures. Without spare conduits, the failure of individual cable sections, or the loss of an entire crossing, would increase the Yorkville network's susceptibility to a shutdown.

- Non-financial Benefits:
  This project would help prevent the negative publicity of a large customer outage on the Upper East Side of Manhattan.

- Technical Evaluation/Analysis:
  Poly Voltage Load flow (PVL) and Network Reliability Index (NRI) considerations will be utilized to determine the best solution.

- Project Status:
  Design – *The Design phase is approximately 5% complete as of March 2017.*

- EH&S Overview:
  The design applies the standards set forth in Corporate Environment, Health, and Safety Procedure (CEHSP) 11.03. The purpose of CEHSP 11.03 is to ensure that environmental, health, and safety (EH&S) considerations are identified and proactively incorporated into the planning and design of project and routine work in order to adhere to regulatory requirements and to achieve environmental, health and safety excellence. In addition, it allows for the consideration of alternate design items to promote resource conservation, reduce risk, and improve project management.

- Financial Overview/Cost Efficiency:
  For the reasons described above, this project was deemed the most efficient means to improve the reliability of the Yorkville network.

- Data Reports Issued that Support Program/Project:
  Before and after analysis of NRI and PVL models will be utilized to support the program.

- Specifications & Procedures Pertaining to Program/Project:
  EO-2072 Method of Planning Reinforcement of Network and Radial Feeders operating at 13, 27 & 33kV.

- Basis for Estimate:

The estimates for this project were created using Work Management System reports and were compared to historic costs for subsurface digging, the installation of conduits, structures, cables, similar underwater river crossings, substation work, as well as splicing and associated work.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-	-	5
M&S	-	-	-	-	-	-
A/P	-	-	-	-	-	455
Other	-	-	-	-	-	-
Overheads	-	-	-	-	-	103
Total	**-**	**-**	**-**	**-**	**-**	**563**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	248	455	611	606	808
A/P	1,752	5,104	4,353	4,267	4,408
Other	176	230	437	428	1,432
Overheads	1,336	2,711	2,323	2,423	2,576
Total	**3,512**	**8,500**	**7,724**	**7,724**	**9,224**

Schedule 5

T&D O&M White papers

System Expansion

	Capital
X	O&M

2019 – Central Operations/System & Transmission Operations

Project/Program Title	138 kV and 345 kV Shunt Reactor Priority Study
Project Number	N/A
Hyperion Project Number	N/A
Status of Project	Planning
Estimated Start Date	January 2020
Estimated Completion Date	December 2020
Work Plan Category	Operationally Required

Work Description:

The scope of work is a Transient Study (the "Study") that would analyze the risks associated with each of the thirty-seven (37) Shunt Reactors on the Con Edison 345 kV and 138 kV transmission system.

The Study would encompass: 1) Data Collection; 2) Electromagnetic Transient (EMT) Model Development and Validation; 3) Feeder Ferranti Effect Overvoltage Analysis; 4) Feeder Energizing Analysis; 5) Feeder De-Energizing Analysis; 6) Normal and Stuck Circuit Breaker Fault/Clear Analysis; and 7) Report and Recommendation.

This Study is necessary to ensure that the Company complies with the applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), New York State Reliability Council (NYSRC) and Con Edison design and operating criteria requirements for the resolution of immediate or anticipated problems impacting the transmission system.

Justification Summary:

There are 37 Shunt Reactors on the Con Edison 345 kV and 138 kV transmission system. Each Shunt Reactor has an assigned priority (Priority 1, 2, 3 or 4) that defines requirements for their operational status; from Priority 1 (must be in-service at all times) to Priority 4 (needed during system restoration). The priority of a Shunt Reactor is primarily driven by transient over voltages, excessive steady state overvoltage conditions and/or surge arrester energy duty limitations.

The upcoming retirement of Indian Point 2 and 3 and/or the possible retirement of the 345 kV B-3402 and C-3403 feeders, among other major topology changes (effective in the next few years), will change how the system is planned/operated; and as such, this Study is intended to establish the Priority designation for each of the 37 Shunt Reactors for the 'new' transmission system so it continues to be operated in a safe and/or reliable manner.

Supplemental Information:

Alternatives:

The only alternative to this Study would be not to perform the Study. However, this alternative is not recommended. The Study is required to establish the future operational priority, due to upcoming major changes to the topology of the transmission system, of each of the 37 Shunt Reactors interconnected on the Con Edison 345 kV and 138 kV transmission system.

Risk of No Action:
Operation of the 345 kV and 138 kV transmission system in an unsafe and/or unreliable manner over an extended period of time with a possibility of a subsequent or an immediate damage to Company's equipment; such as damage/loss of a 345/138 kV transformer affecting customers, up to the loss of customer load.

Non-Financial Benefits:
System reliability is maintained or enhanced. Strategies for system improvements are selected based on the best metrics.

Summer of Financial Benefits (if applicable) and Costs: N/A

Technical Evaluation/Analysis: See Justification Summary, Alternatives and Risk of No Action above.

Project Relationship (if applicable): None

Basis for Estimate:
An estimate was developed based upon previous experience and received scope of Work from a 3rd party that would be the base of this Study.

Total Funding Level ($000):

Historical Elements of Expense:

EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Forecast 2018**
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Request by Elements of Expense:

EOE	**Budget 2019**	**Request 2020**	**Request 2021**	**Request 2022**	**Request 2023**
Labor	-	-	-	-	-
M&S	-	-	-	-	-
A/P	-	190	-	-	-
Other	-	10	-	-	-
Overheads	-	-	-	-	-
Total	-	**200**	-	-	-

	Capital
X	O&M

2019 – Central Operations/System & Transmission Operations

Project/Program Title	Emergent Survey - Specialized Transmission Planning Studies
Project Number	N/A (pending)
Hyperion Project Number	N/A
Status of Project	Planning
Estimated Start Date	2020
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
This program provides a mechanism to support special studies, in case of unplanned events occurring on the transmission system, that cannot be performed by the staff of System and Transmission Operations - Transmission Planning, due to either a lack of appropriate analytical tools or expertise. These studies generally involve areas such as switching and transient phenomena, probabilistic reliability assessment, high-volume rapid contingency analysis, frequency diversions, islanding, and transients related to switching during System Restoration following a partial or total system Blackout.

Justification Summary:
These studies are needed to ensure that the Company complies with the applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), New York State Reliability Council (NYSRC) and Con Edison design and operating criteria requirements for the resolution of immediate or anticipated problems impacting the transmission system.

Supplemental Information:

Alternatives: None. These studies require highly specialized analytical tools and skills.

Risk of No Action: If these studies are not performed, the transmission system could be operated in an unsafe and/or unreliable manner over an extended period of time.

Non-Financial Benefits: System reliability is maintained or enhanced. Strategies for system improvements are selected based on the best metrics.

Summer of Financial Benefits (if applicable) and Costs: N/A

Technical Evaluation/Analysis: See Justification Summary, Alternatives and Risk of No Action above.

Project Relationship (if applicable): None

Basis for Estimate: An estimate was developed based upon previous experience (adjusted for cost increases).

Total Funding Level ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Request by Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	-	-	-	-	-
A/P	-	95	95	95	95
Other	-	5	5	5	5
Overheads	-	-	-	-	-
Total	-	**100**	**100**	**100**	**100**

	Capital
X	O&M

2020 –Central Operations/Substation Operations

Project/Program Title	Cricket Valley Substation
Project Manager	Not Applicable
Hyperion Project Number	Not Applicable
Status of Project	Planning
Estimated Start Date	January 2020
Estimated Completion Date	Not Applicable
Work Plan Category	Operationally Required

Work Description:
This program change is for the operation and maintenance of a new Con Edison facility (Cricket Valley Substation). The incremental operations and maintenance expenses associated with the expansion of the Con Edison transmission facilities include weekly operator coverage, regular preventative and scheduled maintenance, and limited facilities and corrective maintenance.

The operations and maintenance expense is estimated to be $400K per year.

Justification Summary:
Cricket Valley plans to construct a nominal 1,177 MW combined cycle, natural gas-fired generating facility that will be located in Dover, New York ("Facility"). The Facility will consist of three sets of combined cycle units, each with one combustion turbine generator and one steam turbine generator. The Facility will interconnect to certain transmission facilities of Con Edison that are part of the New York State Transmission System. The Point of Interconnection will be at a new 345 kV substation configured as a six breaker ring bus on Con Edison's Line 398. Con Edison will assume ownership and operating responsibilities for the new Cricket Valley substation in 2020. Incremental resources are needed to safely operate and maintain this station.

Supplemental Information:

- Alternatives:
  The only alternative to this program change is to rely on existing resources to operate and maintain the new Cricket Valley Substation.

- Risk of No Action:
  If no action is taken, the incremental resource needs for operating Cricket Valley Substation will have to come from existing availability. This could result in re-prioritization of other existing work to accommodate required preventative maintenance at the new substation.

- Non-financial Benefits: N/A

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: N/A
- Project Relationships (if applicable): N/A
- Basis for Estimate: Similar costs for the operation of an SF6 gas insulated substation

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	320	320	320	320
M&S	-	30	30	30	30
A/P	-	50	50	50	50
Other	-	-	-	-	-
Overheads	-	-	-	-	-
Total	**-**	**400**	**400**	**400**	**400**

Exhibit__(EIOP-5)

T&D Risk Reduction

Schedule 1: T&D Risk Reduction Capital Program and Project Summary

Electric T&D		Year Total			
Risk Reduction		Current Budget			
		Total Dollars ($000)			
		RY1	RY2	RY3	3 Yr. Total
Risk Reduction					
Organization	**White Paper**				
Substations	138Kv Disturbance Monitoring Program	-	2,099	2,400	4,499
Distribution	179th St Area Substation Reconstruction	488	488	488	1,464
Distribution	4kv USS Switchgear House Replacement	6,839	14,960	14,960	36,759
Substations	Area Substation Phased Replacement Program	-	6,000	28,000	34,000
Substations	Area Substation Reliability	14,100	11,500	10,800	36,400
Substations	Bus Auxiliary Equipment Program	1,000	1,000	1,000	3,000
Substations	Category Alarm Program Various	2,150	1,845	2,156	6,151
Substations	Circuit Switcher Replacement Program	1,400	1,400	1,400	4,200
Substations	Condition Based Monitoring	14,100	14,100	-	28,200
Distribution	Critical Facility Program	-	2,000	2,000	4,000
Substations	DC System Upgrade Program	5,092	5,092	5,092	15,276
Substations	Disconnect Switch Capital Upgrade Program	3,300	2,100	2,100	7,500
Transmission	Dynamic Feeder Rating System Program	1,500	1,500	1,500	4,500
Substations	East River Automation - Upgrade The 69KV Yard	-	4,000	3,000	7,000
Substations	Elmsford Disconnect Switches on TR5, 38W24 and 38W14	-	1,135	-	1,135
Transmission	EMS Reliability AECC and ECC	-	300	300	600
Transmission	Feeder 38R51 and 38R52 Replacement Project	23,000	92,800	92,800	208,600
Substations	Fire Suppression System Upgrades	6,500	3,500	10,853	20,853
Substations	Gas Insulated Substation Replacement Program	-	25,000	25,000	50,000
Substations	Hellgate Wharf Refurbishment	2,400	2,500	-	4,900
Substations	High Voltage Circuit Breaker Capital Upgrade Program	10,500	10,500	14,500	35,500
Substations	High Voltage Test Set Program	2,500	4,400	6,500	13,400
Transmission	Joint Replacement Program	5,564	5,200	5,200	15,964
Transmission	LP Resevoir Replacement Program	1,396	2,500	2,500	6,396
Substations	Mobile Control Center	-	-	1,000	1,000
Transmission	Modernization Program CECONY Electric Transmission Feeder Structures	1,976	2,000	2,000	5,976
Distribution	Monitoring Device and Application Program	5,000	5,000	5,000	15,000
Distribution	NonNetwork Reliability (Overhead reliability)	29,476	35,000	27,708	92,184
Transmission	Operations Network For EMS	293	300	300	893
Distribution	Osmose (C Truss)	2,333	2,333	2,333	6,999
Substations	Other Capital Equipment Upgrades	2,538	2,343	2,343	7,224
Transmission	Overhead Transmission Structures Program	1,951	2,000	1,700	5,651
Transmission	Partial Replacement of Feeders M51 and M52	-	67,316	168,250	235,566
Substations	Pothead Pressure Alarms	150	150	150	450
Distribution	Pressure, Temperature and Oil Sensors	2,000	2,000	2,000	6,000
Distribution	Primary Feeder Reliability	7,500	10,761	13,761	32,022
Substations	Pumping Plant Improvement Program	5,462	3,900	3,900	13,262
Substations	Ramapo - Install New Surge Arrestors	1,450	-	-	1,450
Substations	Reinforced Ground Grid Program	3,000	1,609	4,917	9,526
Substations	Relay Modifications Program	12,100	12,100	12,100	36,300
Substations	Relay Protection Communication Upgrades	3,000	3,500	3,000	9,500
Distribution	Remote Monitoring System 3rd Generation	3,222	3,222	3,222	9,666
Substations	Retrofit Overdutied 13kV and 27kV Circuit Breaker Programs	14,830	14,830	12,500	42,160
Substations	Roof Replacement Program	2,127	2,127	2,127	6,381
Substations	RTU Upgrade Program	2,160	2,612	2,510	7,282
Distribution	Shunt reactors	1,290	2,500	2,500	6,290

Schedule 1: T&D Capital Risk Reduction (Continued)

Substations	SSO Loss Contingency Area Stat Rapid Recov/Transm Resiliency Tsfs	-	19,374	-	19,374
Substations	Stabilization of Pothead Stand Supports/Settlement	1,500	2,500	2,500	6,500
Substations	Structural and Infrastructure Upgrades	6,564	7,932	8,150	22,646
Substations	Substation Enclosure Upgrade Program	2,300	1,900	1,900	6,100
Substations	Substation Transformer Replacement Program	71,720	76,640	58,160	206,520
Distribution	Unit Substation Tap Changer Position Indicator	36	38	38	112
Distribution	Unit Substation Transformer Temperature Gauges	95	100	100	296
Distribution	Unit Substation Transformer Replacement Program	6,530	3,902	3,902	14,334
Distribution	Transformer Vault Modernization	15,350	15,350	15,350	46,050
Substations	Transmission Station Metering & SCADA Upgrades	3,066	3,066	3,066	9,198
Substations	U Type Bushing Replacement Program	2,294	2,510	4,720	9,524
Distribution	Underground Secondary Reliability Program	45,000	55,000	55,000	155,000
Distribution	Unit Substation PTO/Unit S/S Modernization	500	500	500	1,500
Distribution	Unit Substation Upgrades and Improvement	1,000	1,000	1,000	3,000
Distribution	Vented Service Box Covers	1,000	1,000	1,000	3,000
	Total Risk Reduction	**360,642**	**582,334**	**661,256**	**1,604,233**

Schedule 2: T&D Risk Reduction O&M Program Change Summary

Infrastructure Investment Panel				
O&M Program Changes				
EIOP - Risk Reduction				
($000)				
		RY1 Program Change	**RY2 Program Change**	**RY3 Program Change**
Risk Reduction				
Organization	**Program Change**			
Distribution	Emergency Response	5,646	(673)	(1,482)
Distribution	Engineering & Other Services*	4,600	200	480
Substations	Hellgate Wharf Refurbishment (SSO Portion)**	800	(85)	(715)
Substations	Roof and Structural Repairs Program	650	-	-
Distribution	Tree Trimming	2,000	-	-
TOTAL ELECTRIC				
	Grand Total	**13,696**	**(558)**	**(1,717)**

**ARCOS White Paper O&M funded under this program found in Schedule 3. Electric Distribution SCADA Enhancement and Outage Management System IT Hardening White Papers associated with Engineering & Other Services found in Exhibit__(EIOP-10) Schedule 3, Communications Infrastructure White Paper associated with Engineering & Other Services found in Exhibit__(EIOP-2) Schedule 2*

***White paper for Hellgate Wharf Refurbishment associated with O&M in Schedule 3*

Schedule 3:

T&D Capital White Papers

Risk Reduction

X	Capital
	O&M

2021 – Central Operations / Substation Operations.

Project/Program Title	138kV Disturbance Monitoring Program.
Project Manager	James Neilis
Hyperion Project Number	PR.20223866
Status of Project	Design/Appropriation/Construction
Estimated Start Date	May 2015
Estimated Completion Date	Ongoing
Work Plan Category	Regulatory Required

Work Description:
This program will increase the amount of Disturbance Monitoring Equipment (DME) deployed throughout the Con Edison 138kV transmission system by installing dedicated DME. This program will also leverage technology to deploy an Automated Substation Control System (ASCS) at each of the 138kV substations to assist in the continuous improvement of operation and controls. This improvement would be achieved through continuous monitoring and analysis of the power system, ensuring a more reliable and robust system. The system would help document and record all system event chronology as well as all impacted relays and equipment. This program will primarily focus on protective relay operations, asset health and indexing, monitoring of protective relay alarms and by generating reports and trends for engineering analysis.

The automatic collection of microprocessor event files will be used for the following functionality:

- Disturbance Monitoring
- Relay Health Monitoring
- Equipment Asset Health Monitoring
- Relay System Maintenance and Testing

The ASCS is a system that includes the DME which is a device capable of recording and monitoring power system data pertaining to system disturbances, and includes digital fault recording (DFR), sequence of event recording (SER), and dynamic disturbance recording (DDR).

The ASCS is required for post incident analysis and fault reporting. It will be the major tool used to analyze system events and take corrective actions. Based on analysis done, fourteen 138 kV transmission substations were required to have DMEs installed based on a high fault level on these stations (greater than 20% of the median per NERC guidelines) we prioritize by Operational Need (Strategical).

Installation of the new DME has been completed at the following Stations:

- Astoria West Completed
- Corona Completed
- East 179 St Completed
- Dunwoodie South Completed
- Greenwood Completed

Installation of the ASCS is required at the following ten transmission substations:

- Astoria East (Construction Start 2017)
- Dunwoodie North
- Tremont
- East 13 St 138kV

- Hell Gate
- Hudson Ave. East
- Jamaica
- Queensbridge
- Vernon
- Eastview

In addition, the three stations below are recommended to be added to the monitoring requirement program in order to provide maximum wide-area coverage for SER and DFR data as well as addressing areas that are sensitive to voltage variations under certain system conditions.

- Buchanan 138kV
- East River 69kV
- Fresh Kills

Justification Summary:
Installation of the ASCS on our 138kV system will provide operational and analytical benefits that have proven to be instrumental in the analysis of previous Con Edison system events. If DMEs are not available, it will be extremely difficult and time consuming to analyze the system events and it will cause delay in restoring the transmission system subsequent to a fault.

Supplemental Information:

Alternatives: There are no specific alternatives to DMEs but some limited DME function can be provided by Microprocessor relays in the system. However, in our transmission system, most of the 138kV transmission stations have electromechanical relays which do not have this capability. Also, it will be difficult and time consuming to get this data from the microprocessor relays as these cannot be accessed remotely due to cybersecurity concerns.

- Risk of No Action:
  No action would lead to continued difficulty in monitoring and analyzing electrical disturbances which occur on the 138kV portion of the Bulk Electric System.

- Non-financial Benefits: This program will increase Con Edison's ability to analyze system disturbances, post event analysis, determine root causes of incorrect relay operations, and validate dynamic models of power system equipment.

- Summary of Financial Benefits (if applicable) and Costs: Financial benefits will include avoiding fine costs for non-compliance.

- Technical Evaluation/Analysis: Controls Systems Engineering performed a study of all the 138kV buses and determined buses needed for sequence of events recording and digital fault recording.

- Project Relationships (if applicable): NA

Basis for Estimate: Current funding request based on costs of work done on the 345kV DME program, which was very similar in nature. The average unit cost averages $1.75 million.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	91	1,624	1,247		733
M&S	-	1,130	1,316	170		60
A/P	-		52	19		8
Other	-	7	36	42		13
Overheads	-	386	1,929	1,110		490
Total	-	**1,614**	**4,957**	**2,590**		**1,305**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	714	821	1,539
M&S	-	-	432	502	927
A/P	-	-	147	168	315
Other	-	-	67	72	132
Overheads	-	-	740	837	1,587
Total	-	-	**2,100**	**2,400**	**4,500**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	E. 179th St Substation Reconstruction Distribution Feeder Transfers
Project Manager	Travers Dennis
Hyperion Project Number	PR.20593360
Status of Project	In Progress
Estimated Start Date	Spring 2011
Estimated Completion Date	Fall 2022
Work Plan Category	Operationally Required

Work Description:
Transfer existing distribution feeders in support of the upgrade and redesign of the bus within 179th street area Substation (S/S). The feeders are being relocated from existing bus sections to the newly constructed bus sections as substation construction completes during the substation reconstruction project.

Justification Summary:
The E. 179th St Substation is the source of supply that feeds the Fordham Network in the Bronx. Reconstruction of the substation, to modernize and make it more reliable, began in the spring of 2011. The plan is to reconstruct the existing substation and convert it in to a double-syn bus design. The plan converts the transition of the area substation over a 10 year period while the station remains in service. As each portion of the station is completed, the distribution feeders must be transferred from the existing switch positions and bus sections to the newly established switch positions. A manhole and conduit system will be built in 2019 to accommodate the transfer of the distribution feeders. The remaining work to install new cable and transfer the distribution feeders from an existing switch positions to the new positions is planned for 2019, 2020, 2021 and 2022.

Supplemental Information:

- Alternatives:
  The alternate is to construct a new double-syn bus designed area substation at a different location.
- Risk of No Action:
  The substation reconstruction will not be completed.
- Non-financial Benefits:
- Summary of Financial Benefits (if applicable) and Costs:
- Technical Evaluation/Analysis:
- Project Relationships (if applicable):
  - East 179th Street–Switchgear and Bus Replacement

- Basis for Estimate:
  Historical costs were applied after a review of the cable and splicing required and the inclusion of a projected 20% obstruction rate.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	10	-	-	-		78
M&S	-	-	16	54		-
A/P	-	-	150	205		238
Other	12	-	-	3		-
Overheads	6	-	107	113		171
Total	**28**	**-**	**273**	**375**		**486**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	30	37	37	66	68
M&S	120	135	133	214	211
A/P	145	137	145	37	36
Other	46	50	51	68	65
Overheads	159	129	122	104	107
Total	**500**	**488**	**488**	**488**	**488**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	4 kV USS Switchgear House Replacement
Project Manager	Colin Ramjohn
Hyperion Project Number	PR.9ES0501
Status of Project	In Progress
Estimated Start Date	2018
Estimated Completion Date	2023
Work Plan Category	Operationally Required

Work Description:
This program will replace aging and deteriorating unit substation switchgear houses with new selected switchgear houses in their entirety (including the circuit breakers they house, which will be upgraded to vacuum circuit breakers). There are 239 unit/multibank substation switchgear houses in the Con Edison non-network system. Their ages range from 1-71 years old with an average age of 53 years.

Current plans are to purchase and install six switchgear houses annually.

This program also includes replacement of the unit substation batteries, which is critical to the performance of the system protection functions. Presently, USS batteries experience a failure rate of approximately 2%.

Justification Summary:
Structural members of switchgear houses have deteriorated due to aging and environmental conditions. These factors have resulted in circuit breakers that do not fit into their cubicles properly. In many instances, pinch bars are used to force the breakers into the cubicles. Forcible insertion or removal of a circuit breaker into or out of its cubicle due to structural degradation often requires de-energization of the unit substation’s 4 kV bus and all feeders. This typically results in a delay in station availability of two or three days.

Rather than attempt to repair the structural problems, this program funds complete replacement of switchgear houses. Spare parts for most of the existing switchgear components are unavailable as many of the original equipment manufacturers are either no longer in business or no longer supply replacement parts.

In addition to the structural problems noted, problems are being experienced with circuit breaker components. Close/trip coils and auxiliary switches have an unacceptably high failure rate (on average 19 failures per year among the older circuit breakers). Ratchet pins, which are utilized in the spring charging mechanism on the older General Electric circuit breakers, fail and are replaced 60 times per year across the system on average. The average time required to repair one of these failed components is between 16 and 32 man-hours. Many spare components (diode/resistor boards, hickory rods, ratchet pins) must be fabricated in company machine shops since many of them are no longer available from manufacturers, and the spare inventory from old decommissioned circuit breakers has been depleted.

Supplemental Information:

- Alternatives:
  Continue to operate and maintain the existing deteriorating switchgear houses. However, as described above, cases of misalignment of circuit breakers and switchgear cubicles result in higher operating and maintenance costs. The older air magnetic circuit breaker technology used in these switchgear houses is less reliable and more costly to maintain than current technology.

  There are some limited cases where it may be possible to upgrade the circuit breakers, protective relays and other components individually, if the overall condition of the switchgear house is deemed structurally sound. However, the cost to upgrade individual components of a switchgear house will exceed the cost of a new switchgear house altogether. An example of this was the Sommer Place #2 feeder breaker upgrade. Costs for this upgrade are summarized in the table below:

Item	Cost
Feeder breaker upgrades	$78,000
Labor (testing, equipment group, etc.)	$156,000
Relay upgrades	$340,000
Total	$574,000

  Despite the new equipment installed, this upgrade retained the existing battery, the 40 plus year old switchgear house and the original "bank circuit breaker".

- Risk of No Action:
  Failure to implement these switchgear house replacements will cause a rise in the overall failure rate due to continued rusting, corrosion and deterioration. This will result in lower reliability due to equipment failure and higher operating, maintenance, and restoration costs.

- Non-financial Benefits:
  Existing switchgear houses frequently contain environmentally unfriendly materials such as asbestos, lead, and PCB's.

  Some of the older switchgear houses have asbestos-containing wire insulation requiring special precautions which increase maintenance costs. For example, Westinghouse circuit breakers contain "Rockbestos" control wiring which are (Asbestos Contain Material) ACMs. There are 53 Westinghouse units among the 239 switchgear houses. In addition, the arc chutes of certain circuit breakers such as Allis Chalmers also contain asbestos. There are 30 Allis Chalmers circuit breakers among the 239 switchgear houses. When abatement is required during the repair of switchgear or circuit breakers, the repair time increases an average of 30%. The new switchgear houses do not contain asbestos and thus maintenance will be less complex and require less time, saving operating costs.

  The new switchgear houses are free of known environmentally unfriendly components.
  Some additional features of the new switchgear houses include microprocessor-based "smart protective relays" that better protect the switchgear and feeders and provide expansion capability for smart grid technologies, an indoor climate controlled environment which would extend the life expectancy of components and a covered aisle which will provide a safe and efficient working environment for maintenance personnel.

Additionally, with the replacements of the old switchgear houses, system reliability will improve thus improving customer satisfaction.

- Summary of Financial Benefits (if applicable) and Costs:
New switchgear requires less frequent maintenance and has fewer parts to maintain resulting in lower maintenance costs over its lifetime. The projected maintenance expenditures for all 4 kV unit substation switchgear houses for 2018 is $0.82M. This is a 39% increase over the 2017 maintenance expenditure of $0.5M for 4 kV switchgear houses.

  As a result of the structural and component problems outlined, periodic maintenance inspections for the older air circuit breakers (ACB) are twice as frequent and twice as costly as compared to the newer vacuum circuit breakers (VCB) employed in new switchgear houses. Since vacuum breaker contacts operate in a vacuum which results in reduced wear on the contacts when the breaker operates, the inspection cycle for most vacuum breakers is six years; the inspection cycle for air circuit breakers is three years. Less frequent inspections for vacuum circuit breakers results in a 50% lower inspection cost as compared to air circuit breakers.

- Technical Evaluation/Analysis:
The Company began utilizing a model/matrix in 2016 to calculate a health index for its unit substation switchgear houses. Based upon that model/matrix, units that have a score outside of the target are recommended for replacement. A unit substation switchgear house with a health index score above the goal runs the risk of an in service mis-operation that would lead to extended repair and having that breaker/feeder out of service for an extended time compromising reliability. There are currently 20 unit substation switchgear houses that are recommended for replacement based upon their health index score. The model/matrix utilizes the following factors in its health index calculation:

  - Age
  - Reliability
  - Maintenance expenditure
  - Asbestos/lead cables
  - Number of feeders
  - Loading
  - Field personnel recommendation
  - Field inspection frequency
  - Status of equipment upgrades
  - Physical condition
  - Flood susceptibility
  - Safety

Based on the switchgear house asset health index, the following switchgear houses have been recommended or replacements in the specified years.

Replacement Year	Unit Substation
2019	Glen Oaks Oakland Arlington #4 Clearview #1 Howard Beach Ralph Ave #1
2020	Centerville Cunningham West Silver Lake #1 Clearview #2 Fort Totten Utica Ave
2021	Ralph Ave #2 Chisolm Willowbrook #1 Floral Park #2 Whitestone East Rosedale
2022	Alley Park Little Neck Floral Park #1 Dongan Hills East 86th St. Union

- <u>Project Relationships (if applicable)</u>
  USS Transformer Replacement Program
  Unit Substation Load Relief
  USS Feeder Breaker Replacement
  USS Life Extension Program
  USS Protection and Feeders Relay Upgrade Program
  USS Site Improvement for SPCC Plans

- <u>Basis for Estimate</u>:
  The purchase price of each new switchgear house is approximately $600K, and the total cost, including overheads, to purchase and install a new switchgear house is $1.5M. These estimates are based on actual expenditures for the two most recent switchgear house replacements.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	68	-	16	395		506
M&S	41	-	1,441	(233)		1,930
A/P	3	-	100	(23)		153
Other	31	-	-	7		52
Overheads	79	-	373	185		770
Total	**222**	**-**	**1,930**	**331**		**3,411**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,144	900	3,060	3,060	1,060
M&S	593	3,879	3,462	3,340	3,468
A/P	272	1,080	5,531	5,531	3,520
Other	155	490	1,358	1,488	1,321
Overheads	557	490	1,549	1,542	591
Total	**2,721**	**6,839**	**14,960**	**14,960**	**9,960**

X	Capital
	O&M

2021 – Central Operations/ Substation Operations.

Project/Program Title	Area Substation Phased Replacement Program.
Project Manager	John McCoy
Hyperion Project Number	PR.23287740
Status of Project	Planning
Estimated Start Date	2021
Estimated Completion Date	2030
Work Plan Category	Strategic

Work Description:
This program will replace 13kV, 27kV or 33kV (medium voltage) equipment at various area substations based on condition assessments. The scope of the program may also include civil work associated with the switchgear, direct current (DC) control cable system replacements and the addition of automation packages for overall station control. The scope of individual projects under this program will be evaluated along with other capital programs, such as 13/27kV Breaker Retrofits, to leverage outage and construction synergies. Through assessments of medium voltage equipment, switchgear housing condition, and DC control cable failures at various area substations, E63rd Street Substation has been prioritized under the program. Area substation locations beyond E63rd Street Substation will be evaluated for similar projects in the future. Engineering and procurement for this program will begin in 2021 and construction will begin in 2022. Due to the complexity of the outage requirements for the East 63rd Street project, construction is expected to continue beyond 2023.

Justification Summary:
The Company typically approaches equipment upgrades in substations at the asset level, through the use of capital programs. This programmatic approach to equipment replacement provides an effective means of managing asset classes at a fleet level while addressing replacement needs at the station level. Under most circumstances this is the most efficient way to maintain the reliability of an individual station. Some substations, due to overall station health, are in need of an approach that is more holistic than the programmatic approach in order to maintain system reliability standards. An assessment of power carrying, auxiliary and structural equipment at a group of area substations has determined that certain locations require capital investment beyond the scope of existing capital programs.

Medium voltage switchgear is the fundamental power carrying component of an area substation. In order to maintain a reliable distribution system, it is essential to have substation breakers, bus, switches and metal clad housing in good working order. The longer a substation is exposed to seasonal extremes, the increased likelihood that the equipment is subject to water intrusion, corrosion and subsequent reliability concerns. Medium voltage switchgear and metal clad housing at some of Con Edison's outdoor area substations have degraded over40-60 years of service. Historically, the Company has made repairs to metal clad switchgear and attempted to install newer sealing technologies to combat weather related degradation. This strategy has been effective with some locations but, even where effective, does not address the actual switchgear. The Area Substation Phased Replacement Program will replace medium voltage switchgear and metalclad housing at locations that are beyond improvement through corrective maintenance.

DC control and instrumentation systems provide remote operability of power carrying equipment, metering and component status indication to operators. A control cable and indication system that is built of copper circuits must be free of corrosion and grounds in order to provide remote operability. When insulation on these lines degrade and grounds persist, it is labor intensive to locate failures and there is a risk that proper instrumentation and control will be lost. During high load periods or contingency conditions, the impact a DC ground on a control cable has on feeder restoration times can be significant. When equipment status indication is unknown due to DC grounds on the station mimic circuitry, the uncertainty brings a risk to operations locally at the substation and remotely at the Energy Control Center (ECC). This program will prioritize the upgrade of copper ground prone control cable systems with networks primarily constructed of fiber optic cables. The program will also replace copper based mimic boards with automation packages. These upgrades will eliminate troubleshooting, provide operators better indications and help to improve the reliability of area substations.

The civil structures that house metaclad switchgear and control cable systems provide environmental protection for the equipment and help operators to perform switching in a safe environment. When exposed to outdoor conditions, civil structures degrade, allowing water intrusion to electrical equipment and the unevening of surfaces. Water intrusion can lead to corrosion and failure of electrical equipment. Uneven walkways and surfaces can make safe breaker racking and other switching moves more labor intensive for operators. The added labor resource required to conduct these operations safely can present a reliability risk during contingency or high load periods. This program will make civil upgrades to walkways and structures in conjunction with switchgear replacement and control cable upgrades.

In order to maintain individual locations, it is important to look beyond individual asset health and recognize conditions that present a systemic risk to the reliability of the substation. Degradation of individual assets can be addressed with corrective maintenance and or capital upgrade programs. When a substation is exhibiting degradation across multiple, interrelated systems, there is a greater reliability risk. A comprehensive assessment of a substation is an essential part of recognizing overlapping risks and deriving a holistic approach to equipment renewal at the station. This program will prioritize capital projects at area substations that are in need of switchgear replacement, control and indication upgrades and civil improvements. This top to bottom approach will improve the reliability of the candidate stations and complete the upgrades in the most efficient manner.

Supplemental Information:

- Alternatives:
  - Repair civil structures, metal clad switchgear and DC control cable systems. This alternative is viable at locations in need of a small volume of repairs. At locations where environmental conditions have combined with vulnerabilities of older technology, a more comprehensive approach is need to combat systemic risks.
  - Replacement of metal clad switchgear, DC control cable, automation installation and civil upgrades will reduce the overall reliability risk at the station.
- Risk of No Action:
  If no action is taken at program targeted area substations, there is a risk that overlapping failures of power carrying and/or control systems will result in customer outages.
- Non-financial Benefits: This program has reliability and safety benefits. The upgrades made through this program will impact reliability by reducing the risk of customer outages due to

overlapping equipment failures. The civil structure improvements made through this program will create a more ergonomic environment for operators to perform electrical switching.

- Summary of Financial Benefits (if applicable) and Costs: The new switchgear and control cable replacements will reduce current O&M expenditures at targeted stations.

- Technical Evaluation/Analysis: The priority for this program was established through analysis of labor hours associated with troubleshooting DC grounds, civil inspections/assessments and feeder processing hours and considerations.

- Project Relationships (if applicable): The upgrade project at East 63rd Street will reuse the medium voltage breakers installed on PN20233-00 as part of the 13kV/27kV Breaker Retrofits Program.

- Basis for Estimate: Order of magnitude estimate based on current engineering estimates. Outer term work based on cost of similar types of work done in the past.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	1,848	8,624	4,650
M&S	-	-	480	2,240	1,178
A/P	-	-	1,080	5,038	2,700
Other	-	-	543	2,659	1,346
Overheads	-	-	2,049	9,439	5,126
Total	-	-	**6,000**	**28,000**	**15,000**

X	Capital
	O&M

2019 – Central Operations / Substation Operations

Project/Program Title	Area Substation Reliability
Project Manager	Robert Brown
Hyperion Project Number	2ES8500
Status of Project	Ongoing
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Regulatory Mandated

Work Description:

This program provides for the installation of high side switching circuits in the substation transformer vaults to provide for redundant clearing. The high side switching circuits shall consist of a circuit switcher and /or an interrupter. Digital Transfer Trip (DTT) could be substituted for one or both of the switching devices where installation is impossible due to space limitations.

After the August 3, 1990 Seaport area substation fire, Con Edison modified substation designs to provide more reliable high speed clearings of transformer secondary faults and reduce the possibility of loss of the area substations during a protracted fault incident. This program provides for the installation of two independent lines of protracted fault protection with electrical and physical separation for the area station transformers. The first line of protection is provided by the installation of a circuit switcher, which is tripped by normal primary protection. The second line of protection is provided by an interrupter, which is tripped by a separate and independent back-up protracted fault protection system located in the transformer vault. If space is limited, then the second line of protection can be provided by a transfer trip relay scheme.

The Auto Ground Switch ("AGS") retirement program has been combined with this reliability program because the AGS can only be retired when either a circuit switcher or transfer trip relay scheme is installed. Where feasible, the retirement of the AGS will be performed simultaneously.

Of the remaining 134 transformers that need to be addressed, fifty-four (54) vaults can accommodate a local high side clearing device (original scope). Due to space limitations and bus-work design, the remaining eighty (80) vaults will be designed with two lines of DTT with a motor operated disconnect or removable flexible link (modified scope).

Substation Reliability Program High Level Status								
Item	Substations	No. of Substations	No. of Transformers (Plan)	No. of Transformers With Two Means of High Side Clearing Devices (2017)	Engineering Phase	Procurement Phase (Long Lead Equipment)	Construction Phase	Estimated Completion Date
1	W110 No.1 and No.2 and E75th Street	3	15	0	40%	80%	0%	2021

2	Brownsville No.1 & No.2	2	10	8	100%	100%	80%	2019
3	Greenwood and Bensonhurst No.1 and No.2	3	11	5	100%	100%	45%	2019
4	Washington and Cedar Street	2	6	4	85%	100%	83%	2019
5	Leonard Street No.1 and No.2	2	14	10	100%	100%	71%	2020
6	Sherman Creek	1	4	1	100%	100%	25%	2018
7	Willow-brook	1	2	1	100%	100%	75%	2019
8	W65 No.1 and No.2	2	10	0	90%	100%	0%	2023
9	E179th Street	1	6	2	40%	40%	33.3%	2021
10	Cherry Street	1	2	0	0%	0%	0%	2022
11	Wainwright	1	2	0	0%	0%	0%	2021
12	E63rd No.1 and No.2	2	14	0	0%	0%	0%	2024
13	Bruckner	1	5	0	0%	0%	0%	2022
14	Buchanan	1	3	0	0%	0%	0%	2024
15	Millwood West	1	2	0	0%	0%	0%	2020
16	Parkchester No.1	1	4	0	0%	0%	0%	2027
17	Avenue A	1	5	0	0%	0%	0%	2027
18	West 19 Street	1	5	0	0%	0%	0%	2027
19	Elmsford No. 2	1	4	0	0%	0%	0%	2024
20	Harrison	1	3	3	100%	100%	100%	Completed
21	Ossining West	1	2	2	100%	100%	100%	Completed
22	E40 No.1	1	5	5	100%	100%	100%	Completed

Note: Construction Phase Status – (No. of transformer with high side clearing devices completed/No. of plan transformers) *100%

Justification Summary:

Con Edison initially developed a single-mode failure concept to prevent extensive damage and station shutdown from a sustained 13kV fault. The concept includes the addition of an independent line of protracted fault protection, installation of a 138 kV transformer circuit switcher and interrupter, the provision for control cable system route separation, separate DC supply systems, switchgear compartmentalization, and improved fire rated design. The design concept changed in 1991 after some substations had been designed and constructed. Upgrading existing area substations to meet the present design concept will reduce the possibility of loss of the area substation during a protracted fault incident. Also, as part of this program Con Edison will look to retire the AGS where feasible.

Con Edison determined that this program offers tremendous value, either through a local high side clearing device (original scope) or two lines of DTT and a motor operated disconnect or removable flexible link (modified scope). In addition to the Seaport type incident protection, these designs allow for faster fault clearing and switching capabilities, which increases operational reliability. The Company evaluated this program in late 2010 /early 2011 and at that time, 134 transformers needed to be addressed in order to meet the 1991 recommendation. Fifty four of these transformers were in vaults that have sufficient space to accommodate a local high side clearing device. In these locations, Con Edison will pursue the original program work. Due to space limitations and bus work design, the Company will

implement a modified scope with two lines of DTT and either a motor operated disconnect or removable flexible link in the remaining eighty vaults.
Con Edison's proposed revision to the original scope of work was reviewed with Staff in 2011. It was determined that the revised plan was a reasonable alternative in light of both space constraints and newly available technology.

Supplemental Information:

- Alternatives: Do nothing: Given the 1991 commitment to complete this program, this would no longer be a viable alternative.

- Risk of No Action: No action would increase the likelihood of a sustained fault on a bus, which can result in extensive damage and the shutdown of an area substation.

- Non-financial Benefits: As noted previously, this program increases overall system reliability and reduces the potential for equipment and facility damage in the event of a protracted equipment fault.

- Summary of Financial Benefits (if applicable) and Costs: NA

- Technical Evaluation/Analysis: NA

- Project Relationships (if applicable): Installation of new equipment for transformers requires outages of the applicable equipment and is subject to system conditions. Where possible, outages for other projects are combined to maximize overall equipment availability on the system.

- Basis for Estimate: Near term work is based on engineering estimates. Outer term work is based on the costs of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	4,538	3,340	2,586	6,501		5,051
M&S	1,375	541	2,139	977		452
A/P	417	952	350	1,034		298
Other	506	255	121	295		103
Overheads	5,492	5,177	3,865	6,516		4,704
Total	**12,328**	**10,265**	**9,061**	**15,324**	-	**10,608**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	5,060	6,782	4,898	4,104	4,075
M&S	760	1,060	1,775	1,728	1,728
A/P	101	141	115	756	756
Other	269	390	317	303	303
Overheads	3,910	5,727	4,395	3,909	3,938
Total	**10,100**	**14,100**	**11,500**	**10,800**	**10,800**

X	Capital
	O&M

2019 – Central Operations / Substation Operations.

Project/Program Title	Bus Auxiliary Equipment Program
Project Manager	Steven Bryan
Hyperion Project Number	PR.22672293
Status of Project	In-Progress
Estimated Start Date	2018
Estimated Completion Date	ONGOING
Work Plan Category	Operationally Required

Work Description:
All substations have critical sections of auxiliary equipment that are required to maintain system reliability, provide accurate feedback for metering/protection, and protect from distressing system transients. These pieces of equipment include coupling capacitor voltage transformers, surge arresters, bushing potential devices, and potential transformers. The ancillary equipment mentioned above has been analyzed on the Con Edison system at the 345kV, 138kV, and 69kV levels. By upgrading these components system reliability will be significantly increased and environmental health and safety improved. This will be accomplished through the Bus Auxiliary Equipment Program using strategic asset replacement approaches.

The objective of this program is as follows:

1. Replace capacitor voltage transformers (CCVT's) and surge arresters system wide with the potential transformers and bushing potential devices to follow.
2. Upgrade the CCVT's, surge arresters, PT's, and BPD's.
3. Prior to and during labor, all aspects of safety will be assessed and handled accordingly to ensure employee and equipment safety.
4. Increase reliability and accuracy over existing voltage feedback equipment. This will provide relay protection and metering equipment more dependable analog signals.
5. Increase reliability of the system under voltage transients.
6. Increase safety of substation personnel by lowering the potential for high energy faults and contaminated spills.
7. Increase protection of high value primary substation equipment by lowering the potential for high energy faults propagating.
8. Decrease potential for negative environmental impact by upgrading equipment with unfavorable dielectric fluid.

<u>CCVT Replacement Basis:</u>

CCVT's serve as major pieces of substation equipment essential to maintaining proper operation and protection. Some of the conditions that could force CCVT failures are described below.

1. Failure in any of the high voltage capacitor elements within the C1 stack
    a. A failure within this section can lead to a catastrophic failure based on the energy associated with these devices
    b. This can also lead to a percentage of secondary voltage feedback distortions based on the number of shorted capacitors in the circuit
2. Failure of any of the capacitive elements in the C2 grounding stack
    a. This can lead to a catastrophic failure dependent on connections and voltage conditions

   b. This can also lead to a percentage of secondary voltage feedback distortions based on the number of shorted capacitors in the circuit
3. Failure of a voltage transformer or series component for voltage feedback
   a. This can lead to incorrect voltage response or incorrect phase angle shift
4. Failure of harmonic suppression filter
   a. This can lead to distortions in voltage waveforms or create an unexpected phase shift
5. Weakening or failure of spark gaps
   a. This can lead to an increased level of wear on the secondary voltage transformers leading to inaccurate secondary voltage readings or an undesired phase shift
6. Multiple possibilities for mechanical failures including but not limited to
   a. Gasket failures
   b. Low oil due to prolonged leaks
   c. Expansion skin failure between capacitive elements and oil insulation
7. Under the failure condition that a CCVT ruptures oil will be lost into the surrounding area. Depending on the type of CCVT it can contain levels of PCB's this is undesirable from the health and environmental perspective.

<u>Surge Arrester Replacement Basis:</u>
Surge arresters play a pivotal role in the protection and stability of power systems. Conditions described below can prevent metal-oxide varistor and silicon carbide type surge arresters from protecting during voltage transients.

1. The most common failures associated with surge arresters can be attributed to moisture ingress. If water intrusion transpires an increase in leakage current and partial discharge can develop leading to over-heating of the arresters and eventually a failure.
2. Aging surge arresters can develop an on-going increase in the resistive element which increases the leakage current creating thermal instability of the arrester.
3. This dielectric integrity can be compromised due to the following conditions
   a. Surge arrester sealing imperfections. Over time the seals will weaken and naturally any flaws from the manufacturing process or installation can develop into areas of concern.
   b. Mechanical fractures in varistor elements attributed to thermal runaway from significant current surges.
   c. External housing weakening due to pollution which can vary voltage distribution across the petticoat insulation stacks.

<u>Bushing Potential Device Replacement Basis:</u>
Bushing potential devices are a key component to step voltages down to a level where protection relays and metering can safely input them. There are numerous components that are required to enable these devices to function properly. If a problem occurs with one of them then the device can give false feedback.

1. Common failures associated with bushing potential devices can be related to the lead-in-cable. This cable runs from the capacitance tap on the high voltage bushing to the primary of the main bushing potential device transformer.
   a. This cable has 7000VAC+ potential (under transients) with a relatively small amount of insulation. This insulation can breakdown over time or be damaged more easily on units that have had more exposure to harsh conditions and human interference.

2. Other failures associated with bushing potential devices can be attributed to a failure of internal components.
   a. Throughout the bushing potential device are multiple transformers and capacitors used to achieve desired voltage output. If one of these components fails it can lead to a dysfunctional device.

b. This can lead to inaccurate inputs to protection which can trip equipment on incorrect feedback.

Potential Transformer Replacement Basis:
Additionally potential transformers play a crucial role in substation protection and metering. It is essential to have them functioning in a proper and safe manner.

1. A significant number of potential transformers have early designs that are on the system which can increase the potential for failure.
   a. These failures can be contributed from multiple factors including excessive voltage transients placed on equipment, excessive heating of potential transformers, or internal winding failures.
   b. If a potential transformer is to fail with a rupture, an oil release will occur. It is crucial to minimize these incidents especially if PCB oil is still existent in the potential transformer. In order to mitigate these risks upgrades are necessary.

Many of the issues described are more likely to occur with equipment that has been in service for extended periods of time and are reaching their end of life. By upgrading the CCVT's, surge arresters, bushing potential devices, and potential transformers using a strategic asset management program the risk of failures can be minimized.

Justification Summary:
Through the bus auxiliary program a significant system wide upgrade will be achieved. Over time there is potential degradation of these devices based on the amount of time in service and if the equipment has been subject to a high number of transients. Due to the high energy associated with these pieces of equipment if a failure is to occur a threat is posed to employee safety in addition to high value equipment in proximity physically and electrically. Undertaking this project will lead to an entire transmission system increase of equipment reliability for Con Edison. Progressing with this asset management program will lead to an overall improvement of safety, asset protection, and operational/maintenance efficiency.

Supplemental Information:

- Alternatives
  1. Increase Maintenance and Testing

     a. One of the alternatives would be to increase maintenance and testing of system wide auxiliary equipment. This would require an impractical number of outages and maintenance. Even if a piece of equipment was found defective through this testing it would need to be replaced on the current our or in the near future. As an example in order to complete one watts-lost test on a surge arrester requires a bus section outage and the arrester to be disconnected from the high voltage connection. To emphasize the magnitude of this there are over 1000 surge arresters throughout Con Edison transmission stations. The testing for a surge arrester is the least complex and time consuming compared to the other targeted equipment in this program.

- Risk of No Action
  1. Taking no action in this scenario would be leaving existing high priority substation equipment in place. If no action is taken system reliability could be compromised. With the current maintenance intervals and equipment status over an extended period of time there is room to miss the signs of approaching failure.

a. In the case that any of these fail aggressively the fault propagation can negatively impact surrounding in-service equipment.
b. If feedback signals are skewed there is room for protective relays to operate erroneously.
c. Hazard can increase to human safety, high value equipment, system reliability, and the environment.

- Non-Financial Benefits
  1. This program will increase safety for all personnel working in and around transmission substations.
  2. This program will increase the reliability of the entire Con Edison power system from transmission level and downstream.
  3. This program will increase the system protection by increasing accuracy of bus voltage feedback.
  4. This program will decrease the risk of damage to other major substation equipment.

- Summary of Financial Benefits
  Through the strategic replacement of bus auxiliary equipment there are multiple financial advantages that will be produced.

  1. These upgrades will prevent major equipment from being damaged under failure conditions
     a. If a failure occurs and a transient is produced the lifespan of primary substation equipment can be reduced.
     b. If a violent failure occurs the potential exists for dielectric fluid to be spilled and for major assets to be damaged.
        - It is an expensive process to clean up dielectric fluid and can have additional fines due to environmental impact.
     c. If failure occurs on the transmission level there is potential for downstream equipment to be effected which can lead to customer outages.
     d. More time and manpower would be used to resolve an unexpected outage or complete maintenance/testing related to that situation.

  Upgrading of CCVT's, surge arresters, bushing potential devices, and potential transformers will provide long term cost reduction by better protecting high value assets, reducing environmental health and safety risks, and keeping customers lights on ensuring company revenue.

- Technical Evaluation/Analysis
  As described above without the bus auxiliary equipment upgrade there are multiple layers of reliability that can be compromised to the overall system. Due to system constraints on testing and evaluating equipment health it is more economical to strategically replace equipment throughout the system. After an overall technical assessment of the transmission system current equipment status, future equipment status, and from past failures that have occurred there is no question that this strategic replacement is necessary.

- Project Relationships
  The strategy that is going to be applied to this system will work in parallel with other projects and outages that are occurring. However, the initial priority will be to replace the most vulnerable assets reaching the end of operational lifespan.

- Basis for Estimate
  The estimate is based on recent replacements of bus auxiliary equipment that has been completed on the 345kV, 138kV, and 69kV voltage classes.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		297
M&S	-	-	-	-		7
A/P	-	-	-	-		47
Other	-	-	-	-		2
Overheads	-	-	-	-		201
Total	-	-	-	-		**554**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	80	190	190	190	190
M&S	143	345	349	350	350
A/P	37	90	90	95	89
Other	37	70	70	69	70
Overheads	113	305	301	295	301
Total	**410**	**1,000**	**1,000**	**1,000**	**1,000**

X	Capital
	O&M

2019– Central Operations / Substation Operations

Project/Program Title	Category Alarm Program – Various.
Project Manager	James Neilis
Hyperion Project Number	PR.8ES3000
Status of Project	In-Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic.

Work Description:
The program consists of replacing failing substation electro-mechanical and solid-state-based alarm systems, which are components of legacy alarm systems that control the activation of alarm points and that, are currently electromechanical switches or solid state devices. They are replaced with a standardized programmable logic controller (PLC), input/output units, and human machine interfaces (HMI). The new alarm annunciator will be equipped with the capability to monitor all the individual station alarms and display their condition on a local computer (PC) and panel mounted touch screen. The PLC will provide local alarm functionality to the station operators and sends category alarms to the Energy Management System (EMS) at the Energy Control Center/Alternate Control Center (ECC/AECC).

Following Engineering Survey Stations currently identified with Legacy Fire Alarm System deficiencies for upgrade include, , Dunwoodie South/North/345kV Mini Bus, E40th St. Corona, Glendale, Buchanan, Harrison, Millwood West, Cedar. Additional units will be evaluated and are expected to be recommended for replacement under this program.

Justification Summary:
The station alarm system provides the operator a general overview of the status of the station equipment, and its reliability and expandability allow for a quicker response time to abnormal conditions. It is of utmost importance that station operations personnel can rely upon the indication and alarms presented to them through the station alarm annunciator.

The legacy alarm annunciator systems have experienced operational problems over the recent years, which results in reliability concerns and high maintenance costs. Many are now at the end of their useful life. These legacy annunciator systems are generally not expandable and unable to accommodate new alarm input points. These systems do not contain alarm history logging, communication capabilities, component redundancy or a backup system in case of a failure. The deficiencies associated with these legacy alarm systems present a risk to system operations.

When an alarm annunciator failure exists, operating personnel need to rely on constant field verification of the station equipment for any abnormal status or alarms, thus the station needs to be staffed around the clock, increasing labor costs. There is limited technical and material supply support from the manufacturers of the targeted systems.

The replacement of the existing legacy alarm annunciator systems will improve operations and reliability by facilitating quick acknowledgement of the alarms and a quick response to abnormal station conditions.

Supplemental Information:

- Alternatives: Repair of legacy alarm system is not possible in many cases as the panel manufacturers no longer supply spare parts or field services for these systems. As these systems reach the end of their useful life, the reliability risk increases. In addition, these systems cannot be modified to accommodate system and operational changes.

  An alternative would be to use any existing spare parts from legacy systems that have been removed. This alternative is not recommended as the reliability of these used parts cannot be verified, nor is there any certainty that this strategy will ensure availability of needed parts.

- Risk of No Action: This is not recommended as the failure of the legacy alarm annunciator system increases operational costs and reliability risk. Dedicated station personnel would be required to perform periodic checks on station equipment should the alarm system fail and no spare parts are available for replacement.

- Non-financial Benefits: A new category alarm system substantially improves and simplifies the station's alarm annunciation and alarm management. It provides the station operator, ECC, and AECC with critical station information not available through the legacy system.

- Summary of Financial Benefits (if applicable) and Costs: The new alarm annunciator system would reduce the high maintenance costs associated with maintaining a failed legacy alarm annunciator system. Without alarms, the operator must monitor the substation equipment periodically to determine operating conditions.

- Technical Evaluation/Analysis: The new alarm annunciator was developed by Con Edison engineering personnel, tested and field proven at multiple company locations. The logic and HMI applications are both standardized to a level where the system requires minimal engineering programming/configuration efforts for individual installations. A core localization text file can be edited either offline using text editing programs or via pop-up windows while the system is running. This file carries the parameters needed for each particular Substation. The debugging of logic and HMI applications will not be required. The system acceptance testing can be limited to verifying that each individual alarm input will trigger a single expected action (i.e., that it is wired properly) and to visual inspections of point configurations at the alarm tile screen(s) (verifying that the displayed information, coming directly from the logic controller, matches the intended operation for each point). The Con Edison universal alarm annunciator system is configurable to provide additional information for each alarm point (drawing references, directions to operators, etc.) and to provide alarm event logs and system configuration data to authorized users or systems, including those residing elsewhere at the corporate network if required.

- Project Relationships (if applicable): This alarm system upgrade program is also linked to the SSO Cyber Security program. The upgrade to a PLC based annunciator system would classify the alarm annunciator system as a Bulk Electric System Cyber Asset. The SSO Cyber Security program would capture the security procedures and guideline required for these alarm systems.

- Basis for Estimate: Near term work based on Engineering estimates. Outer term work based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	563	115	967	887		668
M&S	367	93	311	779		297
A/P	2			12		10
Other	17	1	15	13		4
Overheads	685	147	906	865		506
Total	**1,634**	**356**	**2,199**	**2,556**	**-**	**1,485**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	469	768	664	798	798
M&S	37	64	56	65	59
A/P	287	494	424	478	475
Other	27	43	38	42	43
Overheads	425	781	663	773	781
Total	**1,245**	**2,150**	**1,845**	**2,156**	**2,156**

X	Capital
	O&M

2019 – Central Operations/ Substation Operations

Project/Program Title	Circuit Switcher Replacement Program
Project Manager	Steven Bryan.
Hyperion Project Number	PR.9ES3200
Status of Project	Planning
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
Con Edison is addressing circuit switchers based on their health ranking. This ranking is based upon the multiple factors including jumpers, service type, station risk, SF6 emissions, O&M costs, model, and age and interrupter age reduction factor. This program will upgrade or replace 1-3 circuit switchers per year with a reliable upgraded model. Depending on the scope of work, the cost will range from $200K to $1,000K per unit.

As the program progresses, other circuit switchers will be considered for replacement based on performance, reliability, and lack of replacement parts availability due to obsolescence. This is the switches that have been identified as priority.

Priority	Station	Equipment	
1	Hell Gate Substation	CS-13 Siemens Type CP-CCB	
2	Sherman Creek	CS-5Siemens-Allis C/S	
3	Sherman Creek	CS-6	
4	E179th	CS-5W Siemens-Allis C/S	
5	Seaport #2	CS-9A	
6	West 50th	CS-1	
7	Goethals	CS-R25	
8	E179th	CS-6E Siemens-Allis C/S	
9	Seaport #2	CS-10A	
10	Seaport #2	CS-7A	

Justification Summary:
Having unreliable circuit switchers would compromise the reliability of the station and jeopardize the network that it is installed to protect. Upgrading these units will increase reliability, lower maintenance and operations costs as well as minimizing system exposure.

Supplemental Information:

- Alternatives: One alternative is to replace the entire unit with a new circuit breaker; this would require new wiring, civil construction for a new pad, and more space in the substation would be more costly than performing the recommended upgrade or replacement of the existing circuit switcher, reason why the replacement is the most cost effective solution.

- Risk of No Action: This is not recommended as the unavailability of spare parts increases the risk of extended outages, reduces system reliability, and increases costs for emergency repair in the event of equipment failure.

- Non-financial Benefits: This program is expected to improve system reliability by preventing or minimizing outage duration and/or extension required for failure repair or replacement, or unexpected part replacement during circuit switcher preventive maintenance. Currently, the lead time for some circuit switcher components is up to 20 weeks. This can cause cascading delays in the outage scheduling system, which can affect time sensitive work. If the circuit switcher is leaking SF6 gas this has a detrimental effect on the environment.

- Summary of Financial Benefits (if applicable) and Costs: The replacement circuit switcher will have lower maintenance costs than the existing circuit switcher in poor health condition and no costs associated with maintaining/repairing SF6 leaks.
- Technical Evaluation/Analysis: At present, there are limited options for repairing any problems that occur on the Siemens Linebacker and ABB Vacuum Capacitor Switch VCS circuit switchers as spare parts are limited and long lead time and support offered by ABB is very limited. These circuit switchers are known SF6 leakers which can have a detrimental impact to the environment. They are difficult and expensive to maintain. No other manufacturers fabricate or supply these parts. If the above mentioned circuit switcher fails, this would cause extensive outage duration, reduce system resiliency and reliability, and delay the outage scheduling process due to long lead time for part procurement and the lack of technical advisers.

- Project Relationships (if applicable): N/A

- Basis for Estimate: Funding request is based on historic costs experienced on similar upgrades/replacements of other circuit switchers.

Annual Funding Level ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	180	3345		218
M&S	-	-	245	438		4
A/P	-	-	59	123		108
Other	-	-	11	52		95
Overheads	-	-	218	352		186
Total	**-**	**-**	**713**	**1,311**	**-**	**612**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	156	252	252	252	252
M&S	218	336	336	336	336
A/P	209	308	322	322	315
Other	53	81	73	80	81
Overheads	234	423	417	410	416
Total	**870**	**1,400**	**1,400**	**1,400**	**1,400**

X	Capital
	O&M

2019 – Central Operations/ Substation Operations.

Project/Program Title	Condition Based Monitoring
Project Manager	Steven Bryan
Hyperion Project Number	PR.2ES7900
Status of Project	Ongoing
Estimated Start Date	N/A
Estimated Completion Date	2021
Work Plan Category	Strategic

Work Description:
The purpose of this program is to install condition based monitoring equipment on power transformers to help identify incipient faults, and respond to equipment problems prior to failure thereby improving transformer reliability and help prevent catastrophic failures. The main drivers of this program are maintenance optimization through the integration of condition monitoring and reliability improvements realized by the reduction of unanticipated transformer failures. Preventing catastrophic failures also improves safety as well as reduces the chance for an environmental event (e.g., releasing oil into the environment). The pieces of equipment that are included in the program are the Load Tap Changer (LTC) and on-line dissolved gas-in-oil analyzers (DGOA) monitoring units. Remote communication and automatic alarming is set up between the monitors and a central server to allow authorized personnel to review data from any company location. All new transformers are equipped with TM100 or Tapguard LTC monitoring equipment. As technologies evolve, other monitoring devices will be evaluated for inclusion in the program as deemed effective. The installations are prioritized based on lessons learned for monitoring effectiveness.

Condition Based Monitoring Program will allow the installation and commissioning of 400 Kelman gas monitoring units on substation transformers. This program will equip 422 transformers with an on line DGOA device to predict and possibly prevent a failure of the unit.

Currently, there are 102 devices on the existing fleet of power transformers, reactors and phase angle regulators. Online monitoring through the use of Kelman units will allow substantially continuous monitoring on all of our substation power transformers.

Currently, the primary means of DGOA monitoring is through periodic sampling by the Chem Lab. Chem Lab sampling occurs one to six times per year, versus a daily sampling by the Kelman units. We plan to install 400 units over the course of the next three years on the remaining population and retrofit those transformers where not all of the oil tanks are currently monitored. This will provide a 100% DGOA monitoring on all compartments of our entire large oil power transformer fleet.

This also includes the communications portion of the monitoring units. The initiative is to set up a central server and establish remote communication with the existing and new Kelman units in order to allow authorized personnel to review data, perform data trending analysis, diagnostic analysis and fleet wide monitoring. A secure infrastructure upgrade is needed, which will transfer the Kelman monitoring system (existing and new) onto a new Data Acquisition Network (DAN) with enhanced cyber security.

The current scope of work includes installing on-line DGOA units on transformers where performance and health indicators suggest continuous monitoring would be beneficial.

Justification Summary:
Dissolved Gas-in-Oil Analysis is the most effective means of monitoring the health of transformers. Continuous monitoring of dissolved gasses can detect incipient faults and allow equipment to be removed from service and repaired prior to failure. Monitoring the load tap changer is also an effective means to monitor a vital component of the transformer. The load tap changer is used to dynamically maintain the secondary voltage of the transformer due to load variation and changing system voltage conditions. By monitoring key parameters of the load tap changer, problems can be identified prior to equipment malfunction, thus avoiding system impacts. It also allows for optimization of our maintenance program, thereby reducing costs.

Continuous monitoring can identify abnormal conditions and predict deterioration of components prior to failure. We have been able to remove the equipment from service to perform maintenance and parts replacement prior to performance deterioration or failure. Installation of the monitoring equipment on additional transformers further enhances the reliability for all transformer installations. Existing transformers have been prioritized based upon system importance, equipment costs and specific equipment cases. Transformers at two-bank area stations are identified as “sensitive-stations” and have continuous monitoring to ensure reliable service to customers when one of the units is removed from service. Allis Chalmers have continuous monitoring due to gassing trends that have arisen in these types of transformers. Certain phase shifting transformers will have continuous monitoring based on their health, system importance, and cost of the equipment. Monitors are also planned for specific units that have indicated abnormal operating parameters and/or poor health. The installed cost for each on-line DGOA monitor is approximately $155,000.
Also, concerning the IT portion, the fleet wide monitoring on a single software platform through central server will enhance the ability to respond to equipment problems prior to their failure, effectively avoiding collateral environmental impacts and will be in compliance with cyber security.
This system enhancement program improves our ability to closely monitor the condition of our critical power transformers and hence better schedule our maintenance activities. Condition monitoring is also used as a better indicator for periodic maintenance than time-based maintenance thereby improving transformer availability and reducing overall maintenance costs. The decision to install monitoring is determined by the Transformer Peer Group.

Supplemental Information:

- Alternatives: The alternative is to sample more frequently with our Astoria Chem Lab. This alternative is not recommended as the installation of condition monitoring improves our ability to more readily detect emerging equipment problems prior to failure thereby improving reliability and lowering overall maintenance costs. The Chem Lab has limited resources and a slower response time in sampling than having an online monitor.

- Risk of No Action: This alternative is not recommended as the installation of condition monitoring improves our ability to detect emerging equipment problems prior to failure thereby improving reliability, lowering overall maintenance costs, providing a safe working environment and helping to reduce the risk of an environmental event. On-line monitoring capability is also a commitment to our insurance company so the failure to continue this program risks that we would not have insurance coverage for transformer losses. Existing Kelman monitoring system will continue to be on the existing corporate server with limited cyber security.

- Non-financial Benefits: This program will improve overall system reliability and workplace safety. Continuous monitoring of transformer gassing provides proactive notification of maintenance and performance issues that could ultimately lead to unit failures. These failures could be catastrophic in nature and be accompanied by fire and/or smoking conditions. Gas monitoring provides an opportunity to intercede prior to the units reaching the point of failure and repair or replace them under more ideal conditions.

- Summary of Financial Benefits (if applicable) and Costs: Gas monitoring maximizes the efficiency of maintenance program spending as the condition of the oil is an indicator of the unit's overall health.

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable): N/A

Basis for Estimate: The funding request is based on the recent historic cost of actual unit installations. The average unit cost is approximately $155k, with a plan to install 400 units over the course of the next three years.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	2	49	79	69		2,325
M&S	-	20	39	5,541		6,797
A/P	-	-	10	2		55
Other	-	-	-	-		86
Overheads	(40)	61	77	1,415		2,937
Total	**(38)**	**130**	**205**	**7,027**	**-**	**12,200**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	2,737	2,679	2,721	-	-
M&S	7,219	6,838	6,839	-	-
A/P	281	278	283	-	-
Other	-	-	-	-	-
Overheads	3,863	4,305	4,257	-	-
Total	**14,100**	**14,100**	**14,100**	-	-

X	Capital
	O&M

2020 – Electric Operation

Project/Program Title	Critical Facility Program
Project Manager	Timothy Schlauraff
Hyperion Project Number	PR.23291640
Status of Project	Engineering/Planning
Estimated Start Date	Jan 2021
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
ConED will further enhance circuit hardening to critical facilities located and fed via non-network distribution circuits. Examples of Critical Facilities include fire departments, police departments, municipal buildings used in a command and control capacity during severe weather events, pumping stations, strategic major food retailers and those facilities identified by municipal leaders. The Company has initiated an outreach and has met with and will continue to meet with the various municipalities throughout Westchester in an effort to further enhance those facilities deemed critical by their leadership.

The Company will implement the following strategies to enhance system resiliency during an overhead storm event.

Selective Undergrounding of Overhead Infrastructure
Where there is an opportunity and it is cost effective, we plan to underground selective feeders in order to maximize the benefits to resiliency. In lieu of directly burying the power lines as the sole solution, we will look to deploy aerial cable systems as a predominant method of enhancing reliability during storms. The non-current carrying steel messenger cable, which suspends the aerial conductors, is far stronger and less likely to be downed by tree/limb impact. Aerial cable systems have a far greater likelihood (when compared to open wire) to remain energized during storms - even if knocked to the ground - due to the resilient design of this underground-type cable.

In addition, we will look to create more ATS (Automatic Transfer Switch) fed transformer systems. An ATS system allows for two supplies (a preferred and a redundant alternate) to maintain first contingency design for our customers. With many of the supply feeders being partially underground and partially aerial cable, the chances of the customer remaining in service during storms are significantly higher.

Enhance system flexibility to expedite emergency generation connection
For those areas where additional measures are warranted, we can employ PME (pad mounted equipment) switches which allow us more operational flexibility in terms of connecting generators while expediting the time it takes to have them operational and allows for other back up sources.

Justification Summary:
Emergency Management data predicts that the Northeast Region will experience an increase in severe storms in the future. Currently, Category 1 and 2 hurricanes affect the region once every 19 years and major hurricanes, Category 3 or greater, affect the region once every 74 years.

In 2018, our overhead system experienced severe damage from Nor'easter's Quinn, Riley and Tobey. In addition to these larger named storms, we experienced a number of large unnamed storms that were also devastating, including the April windstorms experienced over April 14th to April 16th where wind gusts reached over 50 mph and a windstorm on May 15th where wind gusts were seen as high as 60mph in the Bronx. Recent experience indicates that the number of these severe weather events is increasing.

Supplemental Information:

- Alternatives:
  The alternative is to continue with our current practices. While these result in industry leading System Average Interruption Frequency Index (SAIFI) performance on a blue sky day, the system remains vulnerable for a large storm event for municipalities and communities which can expect multi-day outages on a more frequent basis.

- Risk of No Action:
  The possibility exists that no severe weather event or storm will hit our service area, but in the event that a major storm does hit the Con Edison service area we will experience severe electric infrastructure damage. This damage is extremely costly to the local communities, the Company and our ratepayers. Blocked streets, lost power and expensive repairs take its toll on the NYC and Westchester County areas.

- Non-financial Benefits:
  Municipalities and communities will be better able to cope and manage through severe weather events that have caused significant damage to the electric infrastructure and power outages. Critical facilities will have a higher probability of remaining in electric service or be restored more expeditiously with emergency generation.

  Customers will have more resources at their disposal and potentially lessen the impact of prolonged repairs to electric infrastructure.

- Summary of Financial Benefits (if applicable) and Costs:
  Although difficult to quantify, the benefits of the program are ensuring enhanced reliability during a major storm. It would enhance local municipalities' ability to manage during severe weather events and provide communities with resources needed while avoiding extensive travel to obtain those same resources.

- Technical Evaluation/Analysis:
  We will follow the standards set in Corporate Instruction CI-260-4 Corporate Response to Incidents and Emergencies which establishes guidelines for determining the appropriate level of response and mobilizing the appropriate Company and external resources in a timely manner in response to any incident. It also describes the Company's Electric Emergency Response Plan (ERP) – The Company's Electric ERP details the organization for the response to storms and manmade events affecting the overhead and underground electric system in accordance with the requirements of Part 105 of the Rules of the New York State Department of Public Service.

  The Company's Corporate Coastal Storm Plan (CCSP) provides a comprehensive overview that attempts to identify the potential effects of a severe tropical storm and/or hurricane, prepare strategies to mitigate these identified risks, and guides the subsequent corporate response to such an event. This guide focuses on ensuring public and employee safety while maintaining and restoring the integrity of our energy delivery services.

Adhering to these processes will also help ensure that EH&S (Environmental, Health and Safety) compliance, resource conservation, risk reduction and alternate design considerations are incorporated in the early planning and design stages of project work. Spill reporting is a primary concern during major storms. This project would limit the amount of transformer spills by preventing damage to the overhead system.

- Project Relationships (if applicable):
  Electric Emergency Response Plan (ERP)

- Basis for Estimate:
  Historical unit costs

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	613	474	481
M&S	-	-	387	673	658
A/P	-	-	81	68	67
Other	-	-	379	290	292
Overheads	-	-	540	495	503
Total			**2,000**	**2,000**	**2,000**

X	Capital
	O&M

2019 – Central Operations / Substation Operations

Project/Program Title	DC System Upgrade Program.
Project Number	Seda Steck
Hyperion Project Number	PR.2ES8300
Status of Project	In-Progress
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Strategic

Work Description:
All substations have redundant DC power systems to provide a reliable source of power during both normal station operations and if all AC power is lost. Each DC system consists of battery banks, battery chargers (rectifiers)/DC converters, load boards with monitoring instrumentation, cables, distribution panels, and disconnect switches. Automatic transfer switches are included for most systems. The DC System Upgrade Program seeks to maintain the highest reliability of substation DC power systems through a targeted asset replacement strategy.

The goal of this program is as follows:

- Assess the DC Systems in Substations and replace equipment, as necessary, in order to ensure:

  1. The system is continuously served with a reliable DC System, including batteries and battery chargers and all other components.
  2. HVAC systems are capable of temperature and hydrogen control for the existing battery room installations in order to achieve optimal equipment performance and a safe working environment.
  3. The highest standard of working conditions for employee health, safety as well as ergonomic considerations.
  4. Reliable battery charger and battery bank operations by maintaining specified battery float voltages
  5. Sufficient DC Power supply to fully meet load demands as per battery design basis.

Battery Replacement Basis
Based on historical test data, battery bank replacement criteria use a combination of battery age and battery condition. Accordingly, the program prioritizes battery replacement banks throughout the system. The Asset Management Group in conjunction with the DC Project Team prioritizes the battery replacements based on age, evaluation of the periodic inspection data, physical condition, in-service experience gathered on different brands, as well as the criticality of the application.

Other Battery Initiates
A pilot project for installing Battery Monitoring Systems on VLA (Vented Lead Acid) batteries has been awarded to a vendor. This system is capable of real-time monitoring of voltages, float, charge/discharge current, unit impedance, etc. Two monitoring systems will be installed on 125 volt DC banks at the

E13th Street Substation. Once in service, these systems will be evaluated for future consideration on expanding the process to other banks.

Battery Charger Replacement Basis
To ensure the battery is kept fully charged and available for a loss of AC power, the DC system needs a battery charger that is operating properly. A properly operating battery charger exhibits stable voltage regulation and is able to maintain optimal battery float voltage. Battery chargers should be replaced if they exhibit excessive voltage drift or ripple current. Battery charger performance can have a significant impact on the battery and its ability and readiness to perform its function.

Load Board Replacement Basis
Load boards serve as the main distribution point for the DC system. Conditions that could force load board replacement are:

- Instrument failure that cannot be replaced due to unavailability of parts.
- Insufficient spare slots for branch circuit breakers, or room on the bus bar to add links, to support station expansion.
- Branch circuit breakers are degraded and cannot be replaced due to unavailability for purchase.
- New DC Load Boards are equipped with the capability of parameter data monitoring and storage as well as a ground detection system on the individual branch circuit. The benefits of these improvements will be factored in during future evaluation of the DC Load Board replacements.

A new DC Load Board was established this year for supplying the newly developed product with the following new features:

- DC system monitoring system, equipped with storage and trending capabilities, and HMI (Human Machine Interface).
- Feeder Ground Detection system which will significantly improve the DC ground troubleshooting
- DC monitoring system to meet the criteria of the NERC monitoring system in multiple DC parameters
- DC circuit breakers will have fast tripping characteristics when needed
- DC load board will have optional transfer switch or tie switch as needed

Justification Summary:
The DC System Upgrade program replaces the DC system batteries in substations that require new batteries (while accounting for DC load growth) and other upgrades to DC system equipment such as disconnect switches, battery chargers , load boards with monitoring instrumentation, DC to AC converters, automatic transfer switches, and associated cables and conduits. The program also addresses HVAC and civil upgrade needs that are specifically related to the previously mentioned work. Delaying these projects can have a negative impact on substation reliability.

Supplemental Information:
- Alternatives:

  1. Maintain (only mandated PMs) – Under this course of action, only preventative maintenance mandated by outside agencies (those for battery banks) would be performed. Degraded

components would not be repaired through corrective maintenance. The material state of certain components, such as individual cells with bad resistance readings or visible damage, would not result in the replacement of such components. This option is rejected for the following reasons:

a. Individual cells of a battery bank could completely fail, resulting in an open circuit condition for the battery bank; this would render the entire bank useless.
b. When a battery bank weakens or losses capacity, the failure might not be known to have occurred until the bank is called upon to operate in a loss of the normal power source. This scenario would result in a reduced or zero time duration supply of emergency power to station DC loads.

2. Maintain (PMs and CMs) – Under this course of action, preventative as well as corrective maintenance would be performed on system components. Despite the expansion of maintenance practices, this is rejected for the following reasons:
   a. A battery bank would still ultimately fail and, as stated above, this failure might not be known until the exact time the battery bank is needed as a source of emergency power for station DC loads. This would result in a reduced or zero time duration supply of emergency power to station DC loads.

3. Capital Overhaul – Although there is currently no provision for capital overhauls, this course of action could be pursued through the targeted replacement of multiple cells within a battery bank. This option is rejected for the following reasons:
   a. When cells of the same age within a bank are replaced with brand new cells, there is a difference in electrical potential between cells of different ages. This difference in potential accelerates the degradation of the older portions of the battery bank and reduces life expectancy even further; this is especially true of battery banks that are nearing end of life.
   b. The same risk of unknown failure mentioned in options 1 and 2 above still exists and has not been mitigated by this course of action.

4. Retire or Employ Different Technology – This alternative could only be implemented for the portions of certain systems after a thorough Engineering evaluation is performed. This option is being pursued where feasible, by retirement of 48VDC battery banks and the installation of DC to AC converters in locations where there is sufficient capacity in 125V battery banks to supply all voltages of DC load.

- <u>Risk of No Action:</u> No action would be to choose not to replace the battery or other system components described above, which would be unacceptable. The basic functionality of a Transmission or Area Substation relies on having reliable, continuous and properly sized DC power available at all times.

- <u>Non-financial Benefits</u>: This program provides reliability, a safe working environment and a sufficient DC power supply. Emergency systems are installed in order to provide a remediation path in extreme circumstances. In the context of the DC system, this circumstance would be a loss of offsite power. It has been deemed an unacceptable risk to allow a station to lose control or supervisory power because it would result in the loss of a substation. The indication of a battery bank failure may be observed in its inability to hold a charge, but it might not be observed until the bank is called upon to meet the demands of the design basis. This uncertainty differentiates battery banks from other pieces of equipment where a run to failure philosophy may be acceptable due to designed redundancy built into the system.

- Summary of Financial Benefits (if applicable) and Costs: NA

- Technical Evaluation/Analysis:
  As described above, our current policy is replacement of VLA station battery banks at the 15 year mark. At the same time periodic tests performed on batteries along with the visual conditions, are used for evaluating the battery banks, and expected performance and recommendations are provided accordingly for maintenance and replacements. In an effort to bring elements of condition based maintenance to the battery replacement criteria, Central Engineering has created a Battery Bank Health Index Spreadsheet prioritizing the battery banks in need for replacement based on overall condition and criticality of the application.

- Project Relationships (if applicable): At times, other capital projects may interfere with the ability to accomplish this work as planned. The interference can be from resource availability, clear physical access, or outage restrictions.

  - Basis for Estimate: Per Environment, Health & Safety (EH&S) direction the DC Project Team ensures the battery upgrade scopes of work are evaluated in a more formal and comprehensive manner by evaluating the entire DC Environment, which ensures a safe working environment for employees. The estimate is based on recent projects with high level scopes that are representative of typical DC Program projects. Typical DC Projects can contain replacements or upgrades to the battery banks, upgrade of the battery chargers (rectifiers) or installation of DC converters, load boards upgrades or replacements, cable upgrades or installations, distribution panel work, disconnect switch upgrades, new automatic transfer switches, installation or overhaul of the ventilation system, and the upgrade of battery room doors.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	991	1,048	1,467	926		1,784
M&S	384	982	1,478	1,906		795
A/P	160	58	305	710		563
Other	30	37	70	29		96
Overheads	1,205	1,454	1,699	1,395		1,434
Total	**2,770**	**3,580**	**5,020**	**4,955**	**-**	**4,672**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,049	1,361	1,380	1,398	1,384
M&S	509	717	713	713	714
A/P	722	1,018	1,019	1,018	1,020
Other	217	305	306	305	306
Overheads	1,118	1,691	1,674	1,658	1,676
Total	**3,615**	**5,092**	**5,092**	**5,092**	**5,100**

X	Capital
	O&M

2019 – Central Operations/ Substation Operations

Project/Program Title	Disconnect Switch Capital Upgrade Program
Project Manager	Bobby. Kennedy
Hyperion Project Number	0ES0700
Status of Project	In-Progress.
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Strategic

Work Description:
This is an ongoing program to retrofit or replace transmission voltage class disconnect switches found to be unreliable based on performance.

Disconnect Switches are upgraded using an overall performance ranking tool, which focuses on three factors:

1. Total number of thermal hot-spots
2. Total number of emergency maintenance outages
3. Total O&M labor hours expended to maintain the existing switches

The entire population is reviewed on a periodic basis by Substation Operations and Engineering. Candidate switches that are chosen for upgrade are then reviewed to determine the overall work scope—retrofit or replacement. Both work scopes consist of the replacement of all current carrying components. A replacement is typically done based on factors such as the structural integrity of the switch itself and/or foundation integrity, and the condition of the porcelain insulators. The disconnect switch program retrofits or replaces approximately 13 disconnects on average per year.

Justification Summary:
This program maintains the current reliability of the system by proactively addressing disconnect switch performance issues on an annual basis. As disconnect switches deteriorate the risk of injury to the public, employees, and interruption of service due to a malfunction increases. Replacing the assets on an emergency basis increases the replacement cost and impacts reliability and safety. Replacement parts are no longer available for many of the assets that meet the criteria of this program.

The program targets switches that have frequently been removed from service on an emergency basis to correct hot spots. These Off On Emergency (OOE2) outages leave the system more vulnerable to service interruptions, particularly during the summer period. Switches that are difficult or impossible to operate are also targeted. These switches can require Operators to "switch around" these assets during both planned and unplanned events. In these cases—additional equipment must be removed from service in order to provide the isolation that would have been provided by the problematic disconnect switch, and this increases the potential for service interruptions.

Supplemental Information:

- Alternatives: Disconnect switches could be maintained according to a time-based maintenance program, however this approach does not focus maintenance dollars on the most unreliable disconnect switches. Of the two options noted above, the lowest cost alternative that will address the existing issues with a particular switch is chosen.

- Risk of No Action: Another alternative is to take no action and allow the disconnect switches to run to failure. The failure of a disconnect switch to operate properly impacts the ability to operate the system reliably and efficiently. Failure to maintain disconnect switches can also result in catastrophic failures, which can have severe system consequences resulting in decreased reliability and safety of operating personnel.

- Non-financial Benefits: As noted above, this program helps maintain overall system reliability, and reduces the likelihood for catastrophic failure of a switch, which is a reliability and safety concern.

- Summary of Financial Benefits (if applicable) and Costs: This program removes the need to repeatedly repair problematic switches that can no longer be reliably maintained, and for which there is limited or no parts availability.

- Technical Evaluation/Analysis: The worst performing disconnect switches are identified by the Disconnect Switch Peer Team through a qualitative and quantitative performance evaluation. The quantitative factors consist of hot spots, O&M labor hours, and emergency maintenance outages (i.e. OOE1 or OOE2).The qualitative factors considered includes parts availability originating from models discontinued or manufactures no longer in business, model, type, year, damaged insulators, and special consideration such as lessons learned from a specific event. The scope of work determined can be unique to each asset however, best management and engineering practices are employed during the scoping, design, planning, and construction process to produce a cost effective and viable solution.

  The retrofit work scope typically includes the following:

  - Replacement of all Current Carrying Parts
    - Blades
    - Jaw Assembly
    - Manual or motorized operating mechanism
  - During the replacement of the current carrying parts, the overall switch is checked for operability, and the following work may be done to ensure that the switch is operating correctly:
    - Ground Switch Operator - - Refurbished.

  The full replacement work scope is used when the replacement of just the current carrying parts of the switch will not restore design function of the disconnect switch.

  The full replacement work scope includes:
  - Replacement of the entire disconnect switch and, where applicable, ground switch, including the current carrying parts and operating mechanisms
  - Upgrade of the steel support structure (where required)*
  - Upgrade of the switch foundation (where required)*

- Replacement of porcelain insulators (where required)

*Note - Reinforcement of the existing Disconnect Switch Stand and/or foundation is required only after a civil engineering evaluation determines that the asset does not meet current IEEE/EPRI findings standards for electrical and structural loads.

- Project Relationships (if applicable): The Corona Substation has disconnect switch issues that are also related to settlement that occurs on equipment foundations in that station. Switches that are being addressed in that station may need to be coordinated with settlement work there, to ensure newly replaced switches will not be subject to settlement concerns. The white paper that references this work is Stabilization of Pothead Stand Supports/Settlement.

- Basis for Estimate: Near term work based on Engineering estimates. Outer term work based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature. The unit cost for a full disconnect replacement is $247k, while the unit cost for a disconnect retrofit is $175k. For 2017-7 replacements and 7 retrofits can be completed, 2018-10 replacements, 2019 and 2021-14 replacements and for 2020-12 replacements completed.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	734	67	493	1,825		1,066
M&S	549	29	597	1,034		1,008
A/P	449	10	23	126		122
Other	4	15	68	490		259
Overheads	1,127	116	593	1,700		1,080
Total	**2,863**	**237**	**1,774**	**5,175**	**-**	**3,535**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	780	1,122	714	714	952
M&S	446	627	399	407	532
A/P	67	99	63	63	84
Other	198	273	183	185	247
Overheads	739	1,179	740	731	985
Total	**2,230**	**3,300**	**2,100**	**2,100**	**2,800**

X	Capital
	O&M

2019– Central Operations/System & Transmission Operations

Project/Program Title	Dynamic Feeder Rating System Program
Project Manager	Vernon Schaefer
Hyperion Project Number	PR.22679442
Status of Project	Planning
Estimated Start Date	Ongoing
Estimated Completion Date	N/A
Work Plan Category	Strategic

Work Description:

This program will provide for a complete system upgrade of existing Dynamic Feeder Rating (DFR) equipment and communications systems to address technology enhancements and parts obsolescence.

This program will include upgrading all instrumentation consisting of Remote Terminal Units (RTUs), input/output signal conditioning, and communication hardware to the latest technologies. Communication systems will be converted from leased third-party hardwire copper systems, including the system DDSII and analog lease lines, to the Con Edison private Ground Penetrating Radar System (GPRS) or Corporate Communications Transmission
Network (CCTN) fiber optic network.

Upgrades of the DFR systems will be performed on the following targeted systems:

Feeders: 25, 26, 45, 46, 47, 48, M51, M52, M54, M55, 61, 62, 63, 71, 72, Q11, Q12, 15055, 29211 and 29212, 18001, 18002

In addition, new ambient temperature earth trees will be installed in selected locations to supplement existing earth ambient temperature measurements utilized for thermal modelling calculations.

This DFR system upgrade program will target two system upgrades per year in 2019-2023. The program will target one system per year for the years 2017-2018. The general priority, based on the material condition of the communication circuits and system criticality, is as follows:

1. M51/M52
2. 61/62/63
3. 25/26
4. M54/M55
5. 45/46/B47/48
6. 71/72
7. Q11/Q12
8. 15055
9. 29211/29212
10. 18001/18002

Justification Summary:

The DFR system is a unique standalone customized system that monitors load, temperature and the system hydraulic status (forced cooling, circulation and static) and adjusts feeder ratings accordingly.

The installation of a DFR system on a transmission feeder, on average, will increase the power transfer capability. The purpose of a dynamic rating system is to maximize the cable system's available capacity in real-time by utilizing critical thermal measurements without exceeding industry defined limits. In order to accomplish this, critical thermal parameters required to execute the rating calculation must be monitored continuously. A dynamic thermal model driven by measured load continuously identifies critical rating parameters. The resulting identified parameters are then used in the rating algorithm that produces the dynamic feeder ratings. Data is received from RTUs installed along the length of the feeder. The data is communicated back to the CPU, which executes the thermo-hydraulic model and associated rating algorithm once every five minutes to establish the dynamic rating of the feeder. This information is then communicated back to a centralized server located at the Energy Control Center, which is then forwarded to the SCADA System. This allows System Operations to operate the electric bulk transmission system utilizing real-time ratings to effectively transfer power during normal and contingency conditions. Since the Company started installing DFRs in the early 1990's, a total of 24 transmission feeders have been equipped and are being operated using the increased power transfer capability obtained from having the DFR rating system. No new DFR installations are currently planned but the Company will continue to consider whether new installations are warranted. The completion of previously started projects to install new DFR installations will be completed in 2015.

The majority of the DFR instrumentation was installed in the 1990s and each RTU runs an 8085 processor in the DOS environment. This hardware is no longer available and the DOS Operating system is no longer supported. In addition, compilers are not available to compile the source code (prohibiting changes to the source code to support changes to the system).

The weakest link in providing near 100% availability of these systems is communications. The existing copper communications infrastructure in the NYC area has deteriorated and is not a priority repair for the third-party communications companies. Their focus going forward is on fiber optic links and wireless communication. As a result, to provide the required reliability, communications must be upgraded to Con Ed owned fiber where available and third-party wireless.

Supplemental Information:

- Alternatives: If the DFR system is unavailable for an extended period of time, System Operators of the bulk transmission system must default to published tabulation ratings, which are typically less than the ratings that are calculated by the DFR system utilizing real-time thermal measurements.

- Risk of No Action: System Operators at the Energy Control Center and their ability to respond to system contingencies on the transmission system will be impacted if the DFR system is out of service.

- Non-Financial Benefits: Several of the feeders selected for DFR system upgrades are also protected by leak detection systems. For these systems, the processing and communication equipment is shared by the leak detection and DFR systems. As a result, the DFR upgrades will also enhance the reliability of the leak detection systems.

- Summary of Financial Benefits (if applicable) and Costs: Not applicable.

- Technical Evaluation/Analysis: The increase in rating provided by the DFR program has clear operational benefits. Cables are able to carry higher loads within industry standard limits. This reduces the dependence on local generation and reduces the probability of having to resort to load-reduction measures, or costly redirection of generation to maintain system integrity. Furthermore, in some cases, the increase in the cables' emergency rating makes it much easier to cope with the sudden loss of any given facility, or contingency. System Operations must always posture the power system to be ready to meet the worst-case contingency, both on an overall basis and within sub-zones known as load pockets. When a contingency occurs, the remaining in-service facilities can be loaded up to their emergency ratings temporarily until adjustments, such as increasing generator outputs, can be made. The increase in emergency ratings provided by the DFR program (in the range of 10-20% higher than tabular ratings) is therefore an important part of maintaining reliable operation of the power system, without sacrificing cable system integrity.

- Project Relationships (if applicable): Not applicable.

- Basis for Estimate: The estimate is based on an Engineering estimate. The funding level is based on a vendor quote and an estimate of the company labor that will be incurred on the job.

Total Funding Level ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	3		30
M&S	-	-	-	386		100
A/P	-	-	-	-		50
Other	-	-	-	-		11
Overheads	-	-	-	68		57
Total	**-**	**-**	**-**	**457**		**248**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	330	434	436	423	259
M&S	460	135	135	440	440
A/P	140	263	260	260	100
Other	310	198	198	200	100
Overheads	204	470	471	177	101
Total	**1,444**	**1,500**	**1,500**	**1,500**	**1,000**

X	Capital
	O&M

2021 – Central Operations / Substation Operations.

Project/Program Title	East River Automation - Upgrade The 69kV Yard
Project Manager	Michael Lentini
Hyperion Project Number	9ES4000
Status of Project	Engineering/Planning
Estimated Start Date	2021
Estimated Completion Date	2022
Work Plan Category	Strategic

Work Description:
This project installs a microprocessor based automation system to perform operating, protective, and monitoring functions for the 69 kV circuit breakers, transformers, phase angle regulators, feeders, and buses at the East River Substation as well as several 138 kV circuit breakers at East 13th Street. This system includes approximately 100 protective relay panels, an operating console with monitors, control and supervisory equipment, and all associated peripheral and support systems including a 125Vdc and 208/120Vac control/auxiliary power distribution. The new components are located in the control room of the 69 kV yard at East River thereby completing relocation of all operating, protective, and monitoring functions from the 8th floor of the East River generating station. The project also retires the existing operating, control, and protective systems and devices currently located in the generating station control room, terminal board room, and various relay rooms.

Con Edison has completed 9 of 13 outages to transfer operating, protective and monitoring functionality to the microprocessor based automation system. The Company plans to complete the remaining 4 section outages by 2022.

Justification Summary:
This project will enhance system performance, improve operator response time and productivity, and upgrade the protection and control systems, thereby increasing reliability. This project is required to support the retirement of the existing operating, control, and protective systems and devices currently located in the generating station control room, terminal board room, and various relay rooms.

Supplemental Information:

- Alternatives:
  Option 1 - Continue to operate the East River Substation as it presently exists. This has three major unacceptable features:
    a. The substation facility would remain undivided from the generating station.
    b. Increased relay mis-operation's and forced outages, caused by the existing wiring and the end-of-life control and relay protection equipment. In addition, much of the existing relay equipment is known to be a cause of mis-operation.
    c. The three-phase Critical Clearing Time, a Con Ed specification determined by T.O. Planning and Engineering, for breaker failure scenarios cannot be met.

Option 2- Implement the cut-over of selected Bus Sections, and leave the remaining Bus Sections using the present wiring and equipment. Sections would be selected based on their connection to either Leonard Street feeders (whose required Area Reliability Phase II work was included in the East River automation design drawings) or to Generating Station outlets.

a. The existing wiring and equipment was impacted by flooding from Hurricane Sandy. The current configuration will not be sustainable.
b. New design requirements specify that elevations for all electrical equipment must be above a minimum of the FEMA plus 3 feet standard.

- Risk of No Action: Lower reliability of the power supply to the Leonard Street substation, and lower reliability for the outlet for East River Gen. #1.

- Non-financial Benefits: This project is expected to improve reliability and reduce the risk of customer outages. Upgrading this equipment will provide better monitoring and control of the station, both within the station control room and from the Con Edison Energy Control Center. This will allow for quicker response to alarms and trip out events, thereby lessening their impact. In addition, this project will reduce the clearing time for faults that occur under certain scenarios, reducing the likelihood of extensive equipment damage in the event of a fault.

- Summary of Financial Benefits (if applicable) and Costs: Avoid Customer service outages.

- Technical Evaluation/Analysis: This project provides for the modernization and life extension of aging plant and equipment. The result of the changes made by this project will be the improved operability and reliability of a substation that serves as an outlet for power generation and supplies two (2) area substations in Manhattan. The completion of the East River Repowering Project at the end of 2005 added 195 MW of new generation flowing through the 69kV substation. This provided an added need to modernize and extend the life of the East River Substation.

  Substation Operations started the program to modernize this aging facility in January 2001. Con Edison completed the project to erect a new building in the 69KV substation, which includes a control room for the 69 kV substation. It was built with adequate space for a new operating console, relay panels, and all support/peripheral equipment required operating the 69KV substation locally or remotely from the Energy Control Center.

  When completed, this project will provide Real Time Human Machine Interface (HMI) screens and protective relay fault/event/oscillography for the East River Substation to selected users via the Con Edison Wide Area Network. Access to the real-time data shall be read only thru a secure firewall. Implementation of the substation automation and protection upgrades proposed by this project is the completion of the multi-phase program started in 2001.

  In addition, the East River 69 kV Critical Clearing Time (CCT) for three-phase fault breaker failure scenarios is 12 cycles. The existing relay protection systems cannot meet this CCT. The 12 cycle CCT can be met by replacement of the 69 kV breaker failure relays and the primary relay protection systems, which is part of this project.

- Project Relationships (if applicable): Implementation will require an outage of each of the East River 69 kV Bus Sections. These outages are contingent on other scheduled and emergency outages at East River and East 13th Street substations.

Previous projects appropriated against this parent budget reference number are 20092-99, 20138-99, and 20156-99 for other East River(ER) substation improvements and upgrades. Expenditures for these projects are included in the cash flow shown below.

- Basis for Estimate: Near term work based on Engineering estimates. Outer term work based on cost of similar types of work done in the past. As this is an ongoing project, work scopes for each bus section are generally similar in nature. This is an ongoing program and has been working for some time. There are also multiple appropriation estimates for various segments of the project.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	**-**	**-**	**-**	**-**		**-**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	1,100	829	-
M&S	-	-	640	482	-
A/P	-	-	500	376	-
Other	-	-	439	334	-
Overheads	-	-	1,321	979	-
Total	**-**	**-**	**4,000**	**3,000**	**-**

X	Capital
	O&M

2021 – Central Operations / Substation Operations

Project/Program Title	Elmsford Disconnect Switches on TR5, 38W24 & 38W14
Project Manager	Bobby Kennedy
Hyperion Project Number	PR.22672415
Status of Project	Engineering/Planning
Estimated Start Date	October 2021
Estimated Completion Date	December 2021
Work Plan Category	Strategic

Work Description:
This project will install disconnect switches on the 138kV bus section side of Elmsford TR5 and the Elmsford end of feeders 38W24 and 38W14.
Disconnect switches do not currently exist at these positions at Elmsford Substation. This project will include the required civil installations to accommodate the disconnects.

Justification Summary:
The Transmission Probabilistic Reliability Assessment (TPRA) is a computer model that helps identify risks on the Con Edison transmission system. The TPRA uses a Monte Carlo simulation and historical failure rates to predict which area substations have the highest probability of load drop due to overlapping equipment outages. Model simulation results are examined to determine potential projects that may reduce the probability of customer load drop at particular area substations. The addition of disconnect switches at Elmsford Substation in the positions mentioned above was identified through analysis of TPRA results.

The TPRA has identified a relative high instance of load drop at White Plains Substation in program simulation runs. Many of these events involve overlapping contingencies where sub-transmission paths from Elmsford to White Plains are lost. The loss of these various transmission paths to White Plains are often not related to problems with the circuits themselves but rather adjacent failures on feeders that are supplied from the same Elmsford bus sections.

The addition of these disconnect switches will greatly reduce the time required to isolate faults on these paths and restore the adjacent paths to White Plains Substation. The reduction in restoration time should reduce the risk of an overlapping event causing load drop at White Plains Substation. TPRA sensitivity studies have predicted this reduction in load drop frequency.
The reliability improvement with the new disconnect switches was demonstrated with sensitivity test using the TPRA software. This project is a cost efficient way to improve reliability and operation flexibility at White Plains and Elmsford Substations.

Supplemental Information:

- Alternatives: The first alternative to this project is to add circuit breakers in lieu of disconnect switches. This alternative achieved a marginally better reliability improvement to disconnect switches as demonstrated by the TPRA. In addition to a potential spacing constraint, this alternative would be of much greater capital cost due to the much higher cost associated with breaker additions.

Risk of No Action: If this project is not completed, there is a risk that equipment failures at Elmsford Substation and associated subtransmission feeders will lead to contingencies at White Plains Substation. If two or more of these failures are coincident and occur at peak load conditions, White Plains Substation may need to shed customer load.

- Non-financial Benefits: The completion of this project will provide Substation Operations with a more efficient means of equipment isolation. With the current configuration, operations must use rental equipment to remove links and apply grounds for scheduled outages. Disconnect switches will allow for quicker equipment isolation.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: The White Plains Substation was identified as a candidate for a reliability project through use of the TPRA software. A high relative number of load drops was predicted by TPRA at White Plains Substation due to the loss of subtransmission paths from Elmsford Substation. Analysis of these model results suggest the installation of isolation devices in two spots at Elmsford Substation. The installation of disconnect switches at Elmsford Substation was deemed a cost effective way to improve reliability at White Plains and this hypothesis was confirmed by sensitivity study using TPRA.

- Project Relationships (if applicable): N/A

- Basis for Estimate: Completed projects of similar scope.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	193	-	-
M&S	-	-	284	-	-
A/P	-	-	272	-	-
Other	-	-	52	-	-
Overheads	-	-	334	-	-
Total	-	-	**1,135**	-	-

X	Capital
	O&M

2019 Central Operations/System & Transmission Operations

Project/Program Title	EMS Reliability AECC and ECC
Project Manager	Michael Threet
Hyperion Project Number	PR.21847145
Status of Project	Ongoing
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing Program
Work Plan Category	Operationally Required

Work Description:
This program will provide software and hardware enhancements to the Energy Management System (EMS) to add needed functionalities and enhancements, meet compliance requirements, enhance error prevention tools, keep a strong cybersecurity posture, and fulfill emergent business needs without having to undergo full system replacement/upgrade of the EMS.

Justification Summary:
Periodic enhancements are needed in order to meet new business requirements and the ever evolving cybersecurity challenges and emergent compliance requirements such as the North American Electric Reliability Corporation (NERC) Critical Information Protection (CIP) standards while promoting reliability, performance and flexibility.

Supplemental Information:

- Alternatives: There are no applicable alternatives to this project.
- Risk of No Action: Not enhancing the Energy Management System (EMS) would cause the system to eventually become less effective in meeting our operational goals and would reduce our overall ability to meet system changes and efficiently manage the electric system, and diminish our ability to anticipate and respond to system events. It could also have cybersecurity and compliance implications and could increase the potential for customer outages and adversely impact customer costs.
- Non-financial Benefits: System Reliability
- Summary of Financial Benefits (if applicable) and Costs: N/A
- Technical Evaluation/Analysis: N/A
- Project Relationships (if applicable): N/A
- Basis for Estimate: History of actual spending on similar work. Note that the historical elements of expense shown in this document included the EMS Replacement project, which is now a separate project.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	355	-	-	60		44
M&S	-	-	-	-		-
A/P	582	329	719	556		200
Other	-	-	-	-		-
Overhead	293	8	13	45		40
Total	**1,230**	**337**	**732**	**661**		**284**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	40	40	40
M&S	-	-	0	0	0
A/P	-	-	219	219	219
Other	-	-	19	19	19
Overheads	-	-	22	22	22
Total	**-**	**-**	**300**	**300**	**300**

X	Capital
	O&M

2020 – Central Operations/System & Transmission Operations

Project/Program Title	Feeder 38R51 and 38R52 Replacement Project
Project Manager	Mark Bauer
Hyperion Project Number	PR.23289097
Organization's Project Number	TBD
Status of Project	Planning
Estimated Start Date	January 2020
Estimated Completion Date	December 2023
Work Plan Category	Strategic Initiative

Work Description:
This project will replace Staten Island 138kV feeders 38R51 and 38R52. Feeders 38R51 and 38R52 originate from Fresh Kills Substation and are the only two supplies for Wainwright Substation. The existing circuits are directed buried, medium pressure fluid filled (MPFF) cables and will be replaced with cross-linked polyethylene (XLPE) cables in new duct banks. Feeders 38R51 and 38R52 have been prioritized for replacement due to environmental, maintenance and reliability performance. Engineering activities for this project will begin in 2020 and construction is estimated to be completed by the end of 2023.

Justification Summary:
The design, physical configuration, routing, maintenance requirements and overall performance of feeders 38R51 and 38R52 present the Company with operational challenges and risks. The feeders are without conduits or protection plates (having only a thin, easily-removed concrete layer over the direct-buried cables), route through protected wetlands and have a submarine crossing at the Fresh Kills Creek. Feeders 38R51 and 38R52 are the only two supplies to the Wainwright Substation. Pressurization of the dielectric fluid needed to maintain the insulation strength of the feeders is provided via dielectric fluid reservoirs at various points along the path of the feeders. This type of cable (having a lead sheath as the only pressure boundary to contain the dielectric fluid) and pressurization system requires frequent outages and a great deal of labor hours to repair and maintain. All of these factors increase the probability that a failure or defect will have an environmental impact or affect the reliability of the transmission system on Staten Island. Due to the obsolete design, topological configuration and maintenance requirements, feeders 38R51 and 38R52 need to be replaced.

Conduits and steel plating play an important role in protecting underground transmission feeders from dielectric fluid leaks, insulation failures or other damage inadvertently caused by excavation activities. Current design standards would require new feeder installations to utilize some type of conduit and, possibly, steel protection plates. Feeders 38R51 and 38R52 are direct buried cables without steel protection plates and are protected solely by an approximately three-inch thick layer of non-reinforced concrete. This configuration carries the risk that subsurface construction activities along the feeder route may damage the circuits, causing a dielectric fluid leak or outage. Given that the circuits follow the same route and are physically close together (only separated by two to three feet in many areas), there is a risk that both feeders could be damaged by such activities at the same time. In 2007, while excavating, a third party contractor damaged feeder 38R52, resulting in an electrical failure. The feeder was out of service for more than two weeks before repairs were completed. During the length of this outage, Wainwright

Substation was in service via one supply feeder (38R51). Any further outage associated with the station would have required load shedding and deployment of mobile generation.

Dielectric fluid leaks on MPFF cable systems pose reliability risk unlike that for high pressure fluid filled (HPFF) cable systems. Unlike HPFF circuits, MPFF circuits must be de-energized to safely facilitate leak repairs. This requirement means that any time either 38R51 or 38R52 is leaking dielectric fluid, an outage must be taken to make repairs. In addition to leak repairs disrupting scheduled outages, they also leave Wainwright Substation in a position where a further contingency will result in loss of customers. Since 2007, feeders 38R51 and 38R52 have had 10 leaks that required circuit de-energization to make repairs. Some of these leaks have been on buried joints and many have been in manholes. As the circuits continue to age, more leaks and associated outages are likely to occur.

A manhole, as a leak location for 38R51 or 38R52, poses another unique reliability risk. Per OSHA regulations, a structure housing an MPFF circuit found to be leaking (considered a D fault condition) cannot be re-entered until such circuit is de-energized. Feeders 38R51 and 38R52 share the same route and have common manholes. This configuration allows the possibility that both circuits could have a leak in the same manhole at the same time. De-energizing both circuits at the same time to facilitate repairs would require temporary transfer of load to stations adjacent to Wainwright and massive deployment of mobile generation.

The routing of feeders 38R51 and 38R52 brings the risk of dielectric fluid leaks to environmentally sensitive areas (wetlands and the Fresh Kills Creek) where repair access may be very difficult. In 2017, 38R52 developed a leak in the Fresh Kills Creek section of the feeder. This event resulted in the loss of over 1,600 gallons of dielectric fluid to the waterway and required multiple, extended outages to make permanent repairs. One of the outages needed to make temporary repairs occurred during a high load period and required the deployment of mobile generation for contingency planning. The cause of the leak was a crack in the lead sheath of the cable due to settlement and movement over time. As feeders 38R51 and 38R52 continue to age and settle further, more leaks of this nature will likely occur.

Due to their design, feeders 38R51 and 38R52 require a great deal of maintenance hours relative to other 138kV circuits. The fluid pressurization reservoirs must be read and adjusted on a routine basis. If one of the feeders is leaking, the frequency of these adjustments increases and continues until the leak is located and repaired. These feeders have historically required between 300-400 labor hours per year to maintain. An analysis of the entire 138kV feeder population in terms of labor hours shows that these feeders are above the average by several standard deviations. XLPE cable systems already in use tend to be significantly less maintenance intensive than MPFF circuits.

Maintaining and repairing feeders 38R51 and 38R52 requires a specialized workforce and non-standard spare inventory. Given that these are the only MPFF circuits owned by Con Edison, new employees do not get many opportunities to splice or perform other repairs on feeders 38R51 and 38R52. Maintaining qualifications and expertise on these circuits is a challenge for the Company. Spare inventory must be carefully managed as the originally equipment manufacturer (OEM) no longer makes the cable used to construct 38R51 and 38R52. Although other manufacturers are willing to make this type of cable, they do so at a financial premium and contingent on long lead times. The replacement of both circuits with a standard, commonly used design would alleviate the personnel and spare inventory burdens associated with MPFF cable.

The replacement of 38R51 and 38R52 with XLPE cable in duct bank would eliminate the environmental and significantly reduce the reliability risks associated with feeders 38R51 and 38R52. The use of an XLPE cable system would eliminate 300-400 hours of maintenance, reduce unplanned outages, improve environmental performance and help to standardize labor expertise and spare inventory.

<u>Supplemental Information</u>:

- Alternatives: Two additional alternatives were looked at for replacement of this project:
  - T-Tapping feeders 38R56 and 38R57 and establishing connections to Wainwright Substation. This option would utilize two of the three supplies to Woodrow Substation by adding wye joints and 2.75 miles of new XLPE ties to Wainwright Substation. This option was rejected for its increased reliability risk. Under this configuration, one feeder outage would affect two area stations and contingency planning.
  - A hybrid XLPE/overhead option. This option would utilize overhead transmission for a portion of the feeder route. This option was rejected because it would introduce the risks associated with overhead transmission such as lightning and storms.

- <u>Risk of No Action</u>: Not replacing or deferring the replacement of feeders 38R51 and 38R52 will increase the risk of dielectric fluid leaks and reliability concerns for Wainwright Substation as the feeders continue to age. By not replacing feeders 38R51 and 38R52, the Company will continue to spend a disproportionate number of hours maintaining the existing circuits. Maintenance and leak response hours will likely increase as feeder leaks become more frequent.

- <u>Non-Financial Benefits</u>: Improved reliability and environmental performance are benefits of replacing these circuits. Replacement of the circuits with XLPE reduces dielectric fluid inventory and, the risk of a leak into an environmentally sensitive area. Without having to perform maintenance specific to these feeders (the "Read and Adjust" work orders,) labor hours will made available for other work on the transmission system. Replacement with XLPE also allows Con Edison to move to more standard equipment which reduces the need for special ordering or special inventory.

- <u>Summary of Financial Benefits (if applicable) and Costs</u>: In company labor alone, Con Edison is spending 30 times more on each of 38R51 and 38R52 than other 138kV circuits. Typical spend for Con Edison labor can range from $50K to over $500K, averaging about $350K per year. Including contractor costs for leaks and emergencies, Con Edison has had several years where over a million dollars in expense have been spent on these circuits. Projecting the maintenance trend forward, it is not unreasonable that the company is projected to spend well over million a year on these circuits. Replacing these circuits with XLPE would eliminate this maintenance need due to the more updated technology. .

  <u>Technical Evaluation/Analysis:</u> Because these feeders are the only two supplies to Wainwright substation, there is a high impact if one or both of these feeders are out of service. Loss of this substation impacts 91MW of load and almost 25k customers. There are several risks which could impact this scenario which include cable which continues to have leaks, the risk of another contractor dig-in, and the risk of a double D-fault in one structure. In the event that there is an outage, repair could be delayed if there is a need to special order cable and obtain skilled employees able to complete this work.

- <u>Project Relationships (if applicable)</u>: None.

- <u>Basis for Estimate</u>: An order of magnitude estimate is the basis for funding requirements.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	1,400	9,600	9,600	1,131
M&S	-	4,103	13,616	13,616	1,142
A/P	-	7,937	36,304	34,000	7,033
Other	-	3,389	6,539	5,839	4,408
Overheads	-	6,171	26,741	29,745	15,186
Total	-	**23,000**	**92,800**	**92,800**	**28,900**

X	Capital
	O&M

2019 – Central Operations / Substation Operations

Project/Program Title	Fire Suppression System Upgrades.
Project Manager	John Dorn.
Hyperion Project Number	PR.2ES8800
Organization's Status of Project	In-Progress
Estimated Start Date	N/A
Estimated Completion Date	N/A
Work Plan Category	Risk Reduction

Work Description:
This program is to perform upgrades, replacements, and/or new installations of fire protection, suppression, deluge system, detection and alarm systems at various substations. The fire detection upgrades include the replacement of fire/heat/smoke detection equipment (inclusive of wiring, control systems, alarm devices, panels, etc.) which is used to detect a fire and initiate an alarm; in many cases this activates a deluge system. The deluge system upgrades include the replacement of piping, pumps, spray nozzles, wiring, control systems, and enclosures associated with delivering water to a fire once a fire is detected. In addition, this program includes the installation of FM 200 Clean Agent System.

This program funds the modification of existing all substation fire protection fire pump piping. These modifications include adding fire pump test headers, valve replacement, piping replacement and work associated with recovering fire system capacity. This covers multiple substations and it is a multi-year initiative that started in 2008.

This program will also fund the installation of clean agent fire suppression systems in various dielectric fluid enclosures (pumping/cooling/Public Utility Regulating Station - PURS plants). This is an ongoing program that began in 2012. ConEdison has identified 57 Phase I locations. This project is a multi-year, multi-phase effort. As part of the Phase I effort, Central Monitoring addition is required on the New York City installations at 27 locations.

Central Monitoring is also required at any location with a lawfully installed Fire Alarm Control Panel. As part of the Letter of Approval initiative, Central Monitoring is required to obtain acceptance of such systems within NYC. This program will fund the installation of third party Central Station Monitoring system upgrades to the existing fire suppression and detection systems at the various substations.

The traditional deluge systems moats capacity are designed to contain at least 20 minutes of water flow from the Deluge Water Spray System. A system to limit the amount of water flow once "no fire" has been detected has been developed and is called a "Cycling Deluge Water Spray System". This Cycling System will automatically shut down the deluge system after 10 minutes of water flow if no heat is being detected. This Cycling system will reduce exposure to spills by minimizing water flow and assist in the Company meeting Spill Prevention Control and Counter Measures SPCC regulations. To install Cycling deluge systems requires the replacement of obsolete deluge valves, in some applications, and in some applications upgrading of deluge valves trim to allow this remote automatic resetting feature. Lastly this automatic re-setting deluge valve is controlled by our standard Fire Control Panel. Likewise here the fire control panel in some locations will require replacements and in some applications upgrading of the standard fire control panels circuitry is required.

Justification Summary:

The fire detection and deluge systems represent a critical component in our ability to quickly and safely respond to a fire event in our substations. The systems we identified not only protect our equipment, but personnel, emergency responders, and the public. The systems installed at our substations are required to comply with National Fire Protection Association (NFPA) and NYC Codes and Regulations, and it is critical that they are maintained in proper working order. Some deluge systems are approaching their expected end of service life, and they are beginning to show signs of deterioration or decreased reliability. Some systems have begun to show excessive leaking, failure to provide adequate flow rates, and/or maintain adequate pressure. At several stations, we have determined that the entire deluge system—including pumps, piping, and controls should be replaced. A number of our fire detection systems show similar end of service life issues. In many cases, replacement detection heads can no longer be obtained, control panel parts are unavailable, and system reliability is compromised.

In past years Con Edison has suffered three incidents that resulted in damage to pumping plants or cooling plants. These events have demonstrated the vulnerability of these enclosures and systems. There are several potential consequences to pumping plant fires. One is the sudden loss of pressurization at the plant, which could affect multiple transmission feeders and electric service to many customers. The other consequence is the potential impact to the public or surrounding structures.

Substation Operations and Electrical Engineering performed a review of existing plants and provided recommendations (report dated 12/21/10) stating that certain facilities (pumping plants, cooling plants, Public Utility Regulating Stations PURS) should be upgraded with fire suppression systems based on their proximity to public property or critical system infrastructure.

System Operations and Electrical Engineering also conducted a study of the importance of each pumping plant on the system during the peak summer load period (refer to white paper "Pumping Plant Improvements – Based on Lessons Learned from Recent Fire Events", by Electrical Engineering Rev 0 dated 5/31/11) and provided recommendations. Efficient Frontier Curves were developed which illustrated the relative efficacy of options to reduce the risk of load drop. The most efficient capital solution to this risk was the deployment of FM-200 fire suppression systems. The pumping, cooling, and Public Utility Regulating Stations (PURS) Plants listed were identified by one or both of these studies as candidates to be retrofitted with a fire suppression system.

The Fire Department now requires official Central Station Monitoring of all new and significantly upgraded fire suppression and detection systems. As such, the company has initiated a project to programmatically install Central Station Monitoring at the various substations that will be connected to the existing fire protection systems and new systems in the future.

Supplemental Information:

- Alternatives:
  1) Some existing systems cannot be upgraded because spare parts are no longer produced. This could leave critical parts of the substation without fire detection and the existing system could become noncompliant with New York City fire codes and standards.

  2) Rely on the operator to routinely check for fire. The system would then not meet current New York City codes and standards. In addition, this is not a practical long term solution, or an efficient use of personnel.

- Risk of No Action: Continuing to operate existing fire detection and suppression systems without upgrades will reduce the reliability and availability of the fire protection systems and increase the possibility of damage to the equipment, environment, personnel and the public. In addition, we could potentially not remain in compliance with the current New York City fire codes and standards.

- Non-financial Benefits: Fire Protection, suppression, and detection systems help to protect essential equipment from extensive damage during a fire. These systems also help guard against collateral damage to neighboring equipment as well as improve personnel and public safety.

- Summary of Financial Benefits (if applicable) and Costs: Limit the cost of damage to operating equipment, personnel, environment and public.

- Technical Evaluation/Analysis: The capability to alert personnel both locally and remotely at the Energy Control Center (ECC) during a fire is critical to the operation and reliability of the station. Lack of functional fire alarm systems could result in extensive damage to substation equipment and could impact personnel safety.

  The ability to alert the Fire Department quickly in the event of a fire is also critical. The quicker the response to a fire and the faster it can be brought under control results in less damage to equipment and disturbance to the operating system. The installation of third party Central Station Monitoring systems associated with the existing fire protection systems at the various substations will improve the notification and response by the Fire Department.

  Modifications, including the addition of valves and a fire pump test header, are required to comply with NFPA and NYC Codes and regulations. The fire pump test header installation will also provide a means to test and evaluate the condition of the fire pumps to ensure proper performance for adequate protection of transformers. The addition of the fire pump discharge valve will improve equipment availability by eliminating the need to shut down all transformer deluge system valves and all fire department Siamese connections while performing the monthly required fire pump operating test.

  In reference to new fire protection, detection, suppression systems, the existing systems have been repaired and/or serviced to the extent possible, but some continue to suffer from unreliable operation or have poor availability. When replaced, the systems are upgraded to meet current local and national fire codes.

- Project Relationships (if applicable):
  Replacement or new installation of fire detection on transformers requires outages of the applicable equipment and are subject to system conditions.

To be Completed 2018:

  - Fox Hills Substation: Install replacement fire controls panels
  - Install FM-200 systems at 57 various pumping plants
  - Queensbridge Substation: Replace deluge valves, valve enclosures and fire detection
  - Goethals Substation: Upgrade station fire detection for transformers
  - West 42nd St. Substation: Fire Detection Upgrade
  - Various Locations: Initiate third party Central Station Monitoring / systems (associated with the new FM-200)
  - Queensbridge Substation: Replace deluge valves, valve enclosures and fire detection

- o Vernon Substation: Fire detection panel upgrade and replace deluge valves
- o E179th Street Substation – upgrade fire detection control panel to cycling and Central Station monitoring. Upgrade deluge piping.

In Construction 2018:

- o Queensbridge Substation: Replace deluge valves, valve enclosures and fire detection
- o Vernon Substation: Fire detection panel upgrade and replace deluge valves
- o Jamaica Substation: New fire suppression system for transformers
- o Various Locations: Initiate third party Central Station Monitoring / systems (associated with existing fire protection systems)

Proposed 2019 – 2023

- o Jamaica Substation: New fire suppression system for transformers
- o Various Locations: Initiate third party Central Station Monitoring / systems (associated with existing fire protection systems)
- o Various Locations: Upgrades to the existing fire detection and suppression systems
- o W65th St Substation: Upgrade fire protection / detection systems
- o Greenwood Substation: Upgrade fire protection / detection systems
- o West 49th St: Upgrade fire protection / detection systems
- o Corona Substation: Deluge system upgrade, (fire pump controller, deluge valves enclosures and detection)
- o East 40th Street Substation #1: Deluge valve replacements
- o Millwood Substation: Upgrade deluge valves and valve enclosures for TR1 and TR2; Add suppression to TA1 and TA2
- o Sprainbrook Substation: Fire detection upgrade
- o Pleasantville Substation: Upgrade fire protection / detection systems
- o Buchanan Substation: Upgrade fire detection / alarm system
- o Rainey Substation: Add new pumphouse and deluge valves and detection for Rainey to Corona projects.
- o Modify, Upgrade or Install New Cycling Deluge Systems at Various locations
- o Ramapo: Install new water main and pump house to increase water flow for fire protection
- o Elmsford: Install new water main and pump house to increase water flow for fire protection

- Basis for Estimate:
  Near term work based on Engineering estimates. Long term work based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,764	1,755	2,937	5,783		2,630
M&S	746	544	718	842		827
A/P	1,093	2,081	(54)	989		2,650
Other	53	(14)	94	497		265
Overheads	2,431	2,968	2,504	4,725		2,561
Total	**6,087**	**7,334**	**6,199**	**12,837**	**-**	**8,933**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,660	2,658	1,400	3,690	1,600
M&S	360	520	315	2,171	350
A/P	480	715	408	760	480
Other	78	129	71	326	80
Overheads	1,422	2,478	1,306	3,907	1,490
Total	**4,000**	**6,500**	**3,500**	**10,853**	**4,000**

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X	Capital
	O&M

2021 – Central Operations/ Substation Operations.

Project/Program Title	Gas Insulated Substation Replacement Program.
Project Manager	John Mazzani
Hyperion Project Number	PR.23287705
Status of Project	Planning
Estimated Start Date	2021
Estimated Completion Date	2029
Work Plan Category	Strategic

Work Description:
This program will replace switches, bus sections, and ancillary equipment at existing Gas Insulated Substations (GIS). The Company has four GIS facilities on the transmission system; W49th Street Substation, Dunwoodie 345kV Substation, Mott Haven Substation and Academy Substation. In a GIS facility, the major high voltage equipment is contained in a sealed environment with sulfur hexafluoride gas (SF6) as the insulating medium. Over time, GIS facilities develop leaks that result in environmental releases of SF6 gas that can lead to moisture ingress into high voltage equipment. SF6 is a greenhouse gas. West 49th Street Substation is the poorest performing GIS facility in terms of SF6 leakage and forced outages due to moisture ingress. This program will prioritize replacement of GIS switchgear at W49th Street Substation. The 138kV sections of GIS equipment at West 49th Street have exhibited the highest frequency of leaks and will be the first sections targeted by this program. Based on ongoing condition assessments, Dunwoodie 345kV Substation may also be prioritized for partial or full switchgear replacement. Engineering for the W49th Street Project will begin in 2020 and procurement and construction will begin in 2021. Due to the complexity of outage scheduling, equipment lead times and construction requirements, the W49th Street project is expected to continue beyond 2023.

Justification Summary:
GIS technology allows for a station footprint that is roughly 10% of the area that would be required of an open air facility. In regions where real estate is at a premium, the reduced area requirements for a GIS facility make station construction and future expansion more economical. The ability of a GIS facility to be indoors also provides protection from weather and mitigates security related risks. As GIS equipment degrades, leakage of SF6 gas may occur. SF6 gas leaks have an adverse impact on the environment and frequently require equipment outages to facilitate repairs. The GIS vintage used at Dunwoodie 345kV and West 49th Street Substations have become less common over time; repair parts and technical oversight of replacements are becoming a challenge. Due to the environmental, reliability and supply chain challenges presented by SF6 leakage, a program is needed for the phased replacement of GIS equipment and W49th Street Substation is the priority location.

The leakage of gas from SF6 containing equipment is monitored and tracked because it is a greenhouse gas. GIS switchgear, including associated high voltage breakers, have the highest volumes of SF6 gas on the Con Edison transmission system. The volume of SF6 gas leaked from W49th Street Substation has accounted for as much as 27% of total Con Edison emissions. Analyzing the volume of gas leaked as a percentage of nameplate capacity, West 49th Street Substation is above that of the remainder of all SF6 containing equipment (see Figure 1). The replacement of the GIS equipment at West 49th Street Substation will reduce overall SF6 emissions.

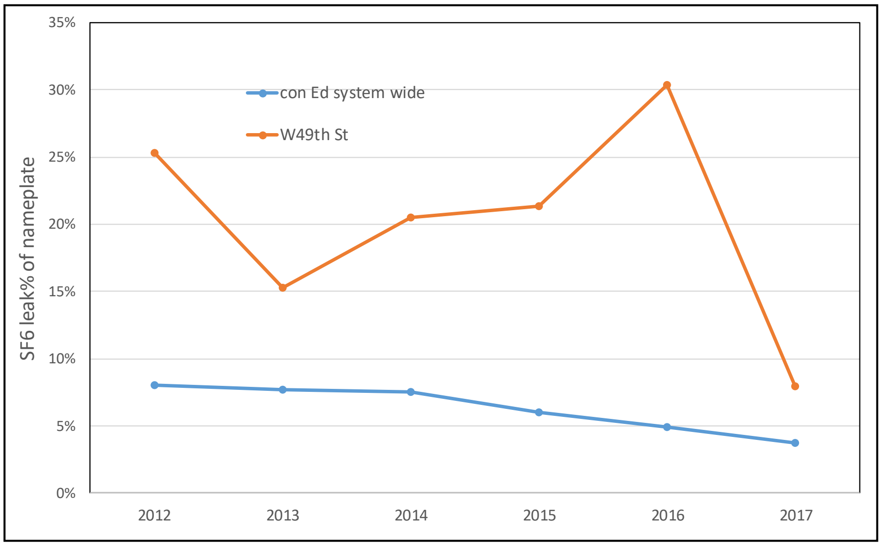


Figure 1 SF6 leakage as a percentage of nameplate capacity for W49th Street vs remainder of system

Leakage of SF6 from GIS equipment can impact reliability in two ways: 1. Outages may be required to facilitate repairs and 2. Moisture ingress requires an outage to correct and can lead to failures. Many leak repairs at West 49th Street Substation have required welded repairs and outages had to be scheduled to accommodate these repairs. In the 2017 to early 2018 timeframe, moisture ingress of the GIS at West 49th Street Substation required outages on 4 different occasions. In the last 3 years, mechanics have had to respond to 59 gas calls related to SF6 leaks at 49th Street. In total, 130 clamps have been installed to stop leaks on the GIS switchgear at West 49th Street Substation. The replacement of the GIS switchgear at West 49th Street Substation will improve reliability on the Con Edison transmission system by eliminating a source of unscheduled outages.

Dunwoodie 345kV and West 49th Street substations were constructed using early GIS technology that has diminishing industry usage and support. ITE was the original equipment manufacturer (OEM) and was absorbed by another company. Technical oversight is necessary to make many replacements on the GIS switchgear and associated breakers and there are few personnel available with knowledge of the old ITE equipment. As other utilities continue to phase out this vintage of equipment, technical oversight and replacement parts will become increasingly difficult to obtain.

SF6 leaks are not the only potential source of unplanned or long term outages associated with GIS switchgear. Disc insulators provide support for the center conductor and form a pressure boundary between different portions of the GIS equipment. During some inspections of the bus and disc insulators, electrical treeing has been observed. If a disc insulator has failed, the replacement parts are typically custom ordered and an extended outage is necessary to complete repairs. This type of failure mode, and the lead time required for repair parts, underline the complexity of reliability and supply chain risks associated with the older generation of GIS equipment.

In order to maintain reliability and mitigate the environmental risks associated with GIS switchgear, a capital program for phased replacement is necessary. Leakage of SF6 gas from GIS facilities contributes to total greenhouse gas emissions and may lead to forced or unscheduled outages. As industry usage of ITE GIS equipment decreases, spare part and technical oversight needs may become a challenge to continued operation. The newer generation of GIS equipment used in substations like Academy and Mott Haven has had minimal issues with SF6 leakage. The replacement of older GIS equipment at substations like West 49th Street and Dunwoodie 345kV with newer equipment will improve reliability and environmental performance.

Supplemental Information:

- Alternatives:
  - Repair
    - The methods to repair GIS include colt clamping, welding and overhaul of sections of the system. The installation of a clamp is a temporary fix and very costly. The clamps add weight to the bus structure and could impact structural integrity.
    - Repairing disc insulators is a current practice, however, it requires long duration outages reducing reliability. w
  - Replacement with like-in-kind equipment
    - This approach is not desirable as the existing design has much higher than desired leak rate. In addition, keeping the existing GIS technology may continue to incur high O&M costs. Like-in-kind will also be second hand equipment as this equipment is no longer manufactured.
  - Replacement with new technology
    - A small section of the W49 Station (bus section 9-10) has been replaced with current GIS technology (similar to that at Mott Haven). There has been minimal SF6 leak at the Mott Haven station; indicating new technology reduces the SF6 emission significantly.

- Risk of No Action:
  - Moisture ingress negatively affects dielectric strength. Once getting onto the system, water molecules may react with SF6, producing corrosive hydrogen fluoride. In case of a fault, the presence of water may lead to toxic substance, generating safety threats, outages are taken to address high moisture level problems, significantly impacts system reliability
  - A high number of temporary repairs (clamps) on the GIS may become the spots for leaks in the future, sustaining high material cost for the SF6 gas leaks and significant corrective maintenance expenditures.
  - Disc insulators require long duration outages to replace.
  - The supply risk in the event of a serious failure since the related OEM since parts may require long lead-time. Moreover, there are only a few similar GIS systems in service worldwide, and the chance manufacturer might stop supporting this generation of GIS technology if other similar stations were replaced.

Non-financial Benefits: Non-financial benefits include improved environmental performance and avoidance of unscheduled outages to repair GIS leaks.

- Summary of Financial Benefits (if applicable) and Costs:
  - In sum, annual O&M costs to manage SF6 issues at W 49th SS are very high, averaging about $600,000 per year only in parts ordering and O & M repairs. . This replacement could save approximately $1.3 million per year in SF6 if emergency response and outage management, parts ordering and O&M repairs are factored in.
  - The new technology reduces maintenance costs, especially corrective maintenance (CM) costs as it reduces the time and efforts in case of repairs.

- Technical Evaluation/Analysis: N/A
- Project Relationships (if applicable): N/A
- Basis for Estimate: Order of Magnitude

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	7,750	7,750	7,713
M&S	-	-	2,000	2,000	2,000
A/P	-	-	4,500	4,550	4,500
Other	-	-	2,195	2,255	2,257
Overheads	-	-	8,555	8,445	8,530
Total	-	-	**25,000**	**25,000**	**25,000**

X	Capital
X	O&M

2020 – Electric Operations/Central Operations/Substation Operations

Project/Program Title	Hellgate Wharf Refurbishment
Project Manager	Dan Brown
Hyperion Project Number	PR.22975771
Status of Project	Engineering/Planning
Estimated Start Date	2020
Estimated Completion Date	2021
Work Plan Category	Operationally Required

Work Description:
The Hellgate wharf is located along the north shore of the East River between East 132nd and East 134th Streets in the Bronx, NY. The wharf supports the Electric Operations' flush truck facility for wastewater barges and Substation Operations' (SSO) heavy lift area for transformer delivery barges.

The wharf structure spans approximately 500 feet and varies in width from 30 to 70 feet. The wharf was constructed on 31ft long by 6ft wide reinforced concrete walls, which are spaced at approximately 30ft-3in on center and founded on rock. Concrete encased steel I-Beams span between the concrete walls and a reinforced concrete deck spans between the beams. Directly inland is a retired concrete discharge tunnel. The wharf and tunnel structures were originally part of the now removed Hell Gate power plant.

The project scope of work is based on a review and analysis of the waterfront from an inspection report compiled by McLaren Engineering in 2016. In the heavy lift area, the concrete encased beams exhibit some form of corrosion, spalling, or cracking. Currently all ten pier walls within this vicinity have signs of severe deterioration including exposed reinforcements, missing concrete covers on caissons, and overall concrete spalling and erosion. There is also evidence of steel rebar corrosion at some walls and supports. Portions of the area are in poor condition with reduced load capacity which restricts the use of the wharf to lighter loads in these areas.

The Flush Truck Facility portion of the wharf, is approximately 150 feet in length and exhibits similar deficiencies to those reported in the heavy lift area. This section of the wharf consists of 3 large bays. There is significant degradation to all decking and missing sections in the northern most bay; the concrete gravity walls have loss of concrete section with exposed corroded steel reinforcing; and the concrete encasement on the deck support beams has failed at many locations, which has led to section loss in the steel beams. Most of the area is unsafe for personnel access and the load rating is restricted to pedestrian loads. The mooring hardware and fenders are also missing in this portion of the wharf. Work in the Electric Operations' area will be performed under a separate project (PN 27306-16).

The SSO work will involve the reinforcing of the tunnel ceiling where sinkholes are present, and extending the high capacity loading area deck to allow the use of longer multi-axle trailers for offloading transformers. It also includes re-establishing a mooring and fendering system for barges. Specific repairs and installations are:

1. Remove and properly dispose of all debris and brick overlaying portions of the Heavy Lift Area.
2. Repair the encased steel girders along the bulkhead in order to adequately support a new concrete slab.
3. Wrap four steel pipe piles in jacketing in order to prevent further corrosion.
4. Water blast the steel beams at the former Roll Off-Roll On (RoRo) platform to remove moderate corrosion and reapply protective epoxy coating.
5. Properly clean and prepare deteriorated areas of concrete and apply a bonding agent and repair mortar.
6. Repair voids at the concrete bearing soffits where the deck steel beams rest.
7. Seal the 24' long crack on the Heavy Load Area.
8. Install a structural slab in two areas over the discharge tunnel's partially collapsed ceiling and restore paving once complete.
9. Extend the heavy lift area east and west by installing a new two way slab over the existing one designed to span the entire length between each pier wall independently of the encased steel beams. The beams shall be repaired to handle the increased loading.
10. Install a new fender system secured to the face of the dock since current fenders are damaged or nonexistent. The system shall be designed according to maximum calculated energies associated with routine berthing maneuvers for the largest barges to dock at the wharf. Install a new bollard on the extended portion of the Heavy Lift Area. Fill existing steel bollards with concrete as recommended by the manufacturer. Clean and recoat them in order to prevent future corrosion. Patch spalls or other localized pockets from impact damage using conventional concrete placement at the eastern faces of the walls supporting the wharf which will receive fenders.
11. Install a permanent fence, railing, or other form of protection along the water's edge.

The Electric Distribution Work will involve remediation of the concrete spalls and steel corrosion on the existing concrete gravity walls; plugging a sinkhole adjacent to the concrete bulkhead; removal of the existing decking, debris and concrete encased beams; installation of new steel beams and a concrete deck; and installation of a new fender system and mooring hardware.

Justification Summary:
The refurbishment of the Hellgate wharf will allow for the long term offloading of effluent from the Flush Truck Facility; and heavy equipment, such as transformers, in a safe and efficient manner from the SSO portion of the wharf. The expansion of the heavy lift area will allow more flexibility in positioning existing multi-axle trailers and allow the use of longer transport vehicles in the future. The restoration of the fendering and mooring systems will provide a safer means of barge docking along with flexibility in vessel types and positioning. Materials will be chosen that suit the harsh marine environment and the design will meet all applicable codes and standards. The project will benefit the Company by reducing the likelihood of injuries and establishing a more reliable offloading facility.

Supplemental Information:
Additional information to reinforce the justification

- Alternatives:
  SSO: One alternative is to restore the wharf back to its previous condition and not extend the unloading area. Although this would reduce the project cost and address structural deterioration,

it would restrict the present and future use of the wharf to barges and trailers that can maneuver and fit into the limited space. This would slow the offloading and delivery process and limit the choice of vessels and trailers, possibly impacting outage durations and electric reliability.

- Risk of No Action:
  SSO: If the wharf is not refurbished, it will continue to deteriorate and there is a risk that additional unsafe conditions and eventual collapse will occur. In addition to increasing the risk of employee injuries, not doing the project will jeopardize the use of the facility for offloading transformers which will impact the reliability of our electric system, especially during unplanned outages.

  Distribution: No action will result in operations continuing to use "work arounds" to accomplish the task of offloading effluent to the barges. The barges will continue to be moored in the heavy lift area and long hoses, that present a safety concern, will need to be run from the pit to the barges.

- Non-financial Benefits:
  SSO: In addition to an improvement in personal safety and offloading efficiency, the refurbishment of the Hellgate wharf will improve electric system reliability by allowing for an efficient delivery and transport of critical equipment. Potential navigation hazards created by deteriorating structures falling into the river will also be eliminated.

  Distribution: The availability of a new wharf adjacent to the Flush Truck Facility will provide a safer work area and improve the efficiency of the effluent offloading operation; as well as eliminating the potential for navigation hazards due to falling debris from the deteriorated wharf structure.

- Summary of Financial Benefits (if applicable) and Costs: **NA**

- Technical Evaluation/Analysis:
  McLaren Engineering conducted a routine Waterfront Inspection of the Hellgate substation and surrounding area. The waterfront consists of a wharf structure and discharge tunnels from the former Hellgate generating station. The inspection report includes a structural analysis of the existing structures and mooring system and recommendations to restore them back to their intended function for receiving barges and delivery trailers.

- Project Relationships (if applicable): Planned and Emergency transformer replacements

- Basis for Estimate: Order of magnitude Estimate: Engineering Estimate

Annual Funding Levels ($000):

Electric Distribution

Capital

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	80	52	-	-
M&S	-	285	194	-	-
A/P	-	177	302	-	-
Other	-	98	79	-	-
Overheads	-	210	223	-	-
Total	**-**	**850**	**850**	**-**	**-**

O&M

Future Elements of Expense (funded in Emergency Response Program)

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	336	280	-	-
M&S	-	4	3	-	-
A/P	-	251	209	-	-
Other	-	10	8	-	-
Total	**-**	**600**	**500**	**-**	**-**

SSO

Capital

SSO Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	600	625	-	-
M&S	-	396	419	-	-
A/P	-	360	375	-	-
Other	-	261	277	-	-
Overheads	-	783	804	-	-
Total	**-**	**2,400**	**2,500**	**-**	**-**

O&M

SSO Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	40	36	-	-
M&S	-			-	-
A/P	-	709	634	-	-
Other	-	51	45	-	-
Total	**-**	**800**	**715**	**-**	**-**

X	Capital
	O&M

2019 – Central Operations/Substation Operations

Project/Program Title	High Voltage Circuit Breaker Capital Upgrade Program
Project Manager	Bobby Kennedy
Hyperion Project Number	PR.10105998
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Strategic

Work Description:
This program combines and continues the 138kV and 345kV capital upgrade programs that ended in 2012. The program scope has expanded to include 12, 27, 33 and 69kV breaker replacement or upgrades. The work scope includes the replacement or capital upgrade of 138kV, 345kV, 12kV, 27kV, 33kV and 69kV (not including work covered under the 13/27 Breaker Retrofit Program) breakers based on their performance in accordance with guidelines established in CE-ES-1000. These breakers will be targeted for replacement when major maintenance is required in accordance with the EPRI maintenance ranking program and subsequent Peer Team review as directed by CE-ES-1000.

A breaker is replaced when it is deemed to be in poor performing condition due to progressive deterioration, lack of spare parts, high maintenance costs, oil and / or gas leakage, poor performance history, or if replacement is more economical than an overhaul. The following breakers have been targeted for replacement:

Breaker Type	Reason for Replacement
Westinghouse 1380SF6 138kV Breakers	• Poor performance • SF6 leakage • In-service failures • Maintainability issues
Oil-filled Breakers	• Poor performance • Environmental concerns • High cost of maintaining 50-60 year old units • Inability to obtain replacement parts • Risk of a major substation event
345kV SFA Breakers	• SF6 leakage

Each breaker replacement will be reviewed individually to provide the business case for its replacement. If the replacement costs are too high or if other factors determine that the replacement is not justified, then other maintenance plans, such as an overhaul, will be explored.

The funding for this program will support approximately 4-7 breaker replacements per year across the various voltage classes.
This program is also expected to fund the relocation of TRV (Transient Recovery Voltage) capacitors on approx. 88 High Voltage Breaker 345kV to address a design issue with the existing units. During switching operations of newly installed HVB circuit breakers in Pleasant Valley, it was observed that

alarm cards and other devices in the control room experienced a surge that caused them to fail. Other HVB circuit breakers have also experienced issues with terminal blocks burning, heaters failing etc. These failures are attributed to the TRV (Transient Recovery Voltage) capacitors mounted on the external bushings of the breaker. The surges occur during adjacent disconnect switch operations.

The circuit breaker candidates for replacement are listed in the 5 year budget plan. Additional circuit breakers, not shown on this list, may be chosen for replacement based on their performance.

<u>2018 - 2020 Planned Work:</u>

- Farragut: 3E, 4E, 9E, 9W and 11W
- Pleasant Valley: RN3, RNS3, RS3, RNS5, RS5
- Sprainbrook: RN6RS2, RS3, RN3, RN4, RNS4, RN5., RNS6
- Sprainbrook TRV Relocate: RN4,RNS5, RS6, RNB2, RNB6, R4S3, R5S3
- Greenwood 27kV: CAP1, CAP2, CAP3
- Jamaica 27kV: CAP1, CAP2, CAP3
- North Queens 27kV:C1, C2, C3
- Buchanan: BT3-4 E13th St.: BT9-10, T4, T9, BT2-1
- Astoria: 4E
- Sheman Creek: 2E
- Vernon: 9W
- Dunwoodie: 4S, 6S, 6N, 7AN, 9S
- Fresh Kills:, 62S, 81S,
- Fox Hills: 21S, 41S,

Other units may be added to this program due to emergent issues discovered on other breakers.

<u>Justification Summary</u>:

This program drives a significant reduction in operation and maintenance costs, SF6 emissions, and forced outages. In the last few years, Con Edison has seen a decrease in labor hours for corrective maintenance on high voltage breakers and SF6 emissions by over 50%.

The reliable operation of circuit breakers is required during any system disturbance to effectively isolate that disturbance from the system. Failure to do so can have serious system consequences and affect customer service reliability. The proper isolation of system disturbances is also critical in maintaining a safe working environment for station personnel as well as safety to the public. Breakers will be replaced when they have become unreliable or when replacement is more cost effective than frequent repairs. In addition, this program will reduce future maintenance costs such as special custom fabrication of unavailable replacement parts and expensive SF6 gas replenishment.

<u>Supplemental Information</u>:

- <u>Alternatives</u>: An alternative is to overhaul or replace circuit breakers based on lifetime of the unit. This method was employed up through 2008. While it did maintain the reliability of circuit breakers, it was not the most effective or efficient method to maintain the circuit breaker fleet. Advances in database record keeping, on-line monitoring systems, and maintenance ranking programs have allowed the circuit breaker maintenance program to be more accurately evaluated through a performance-based method. The time-based maintenance method is therefore not recommended.

  Another alternative is to perform no overhauls or replacements of circuit breakers. This is not recommended because of reliability, system performance, environmental, and safety concerns.

- Risk of No Action: Failure to replace these breakers would significantly affect the operation of the electric system as well as result in environmental and safety concerns. The failure to address the deteriorating oil circuit breaker population would have similar effects.

- Non-financial Benefits: Replacement of the identified class of breakers has helped Con Edison to reduce environmental incidents such as SF6 gas emissions and oil spills.

- Summary of Financial Benefits (if applicable) and Costs: The 345kV SFA breakers have been targeted for replacement. A new overhaul to address the various problems of this breaker type was approaching $900k, while the total replacement cost for this unit is approximately $2 million dollars (labor and material). There are currently two classes of 138kV breakers that have been identified for replacement (OCB and Westinghouse 1380) due to their high failure rate, high cost of repairs and overhaul, and maintenance history problems. The 33kv class of breakers has been recently added to the overall breaker replacement program due to observed degradation. These increased failures have impacted both residential and commercial customers, which affects SAIFI performance.

- Technical Evaluation/Analysis: The reliable operation of circuit breakers is required during any system disturbance to effectively isolate that disturbance from the system.

  The replacement of the selected breakers will address the operational, reliability, environmental, and cost concerns. The new breaker types that are being installed have been used extensively in our 345kV and 138kV circuit breaker upgrade program, and have provided an improved maintenance record and have enhanced the reliability of the system.

- Project Relationships (if applicable): NA

- Basis for Estimate: Near term work based on engineering estimates. Outer term work based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature. The average unit cost for purchase and installation of a 345kV breaker is $2.0 - $2.5 million, which will allow for the purchase and installation of four to seven breakers per year. The cost for a 138kV breaker is comparable, with the material cost slightly less. It should also be noted that there could be carryover work from the previous year.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	3,469	2,754	916	4,115		3,244
M&S	1,939	1,827	1,002	5,220		1,749
A/P	336	253	306	912		2,594
Other	341	(2,173)	55	508		367
Overheads	4,735	4,116	991	4,583		2,796
Total	**10,820**	**6,777**	**3,270**	**15,338**	-	**10,750**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023

Labor	2,490	2,914	2,914	4,024	4,024
M&S	2,490	3,150	3,150	4,350	4,350
A/P	498	630	651	957	899
Other	224	282	310	434	433
Overheads	2,598	3,524	3,476	4,735	4,794
Total	**8,300**	**10,500**	**10,500**	**14,500**	**14,500**

X	Capital
	O&M

2019 – Central Operations/ Substation Operations

Project/Program Title	High Voltage Test Set Program.
Project Manager	Steve Bryan
Hyperion Project Number	PR.2ES8400
Status of Project	In-Progress
Estimated Start Date	N/A
Estimated Completion Date	N/A
Work Plan Category	Strategic

Work Description:
This program funds the purchase and installation of DC and AC high voltage test sets that are used for feeder processing on the Con Edison distribution system. It also provides funding for required ancillary equipment, such as a power feed for the test set, or test leads that bring the set outputs to the feeders being tested throughout the station. In addition, this program funds the purchase and installation of protypical AC/DC test sets, which will provide the critical functionality of both types of test sets into a single unit.

DC High Pot Test Sets
There are 119 high voltage DC test sets in Substation Operations that are used for distribution feeder processing.
AC Very Low Frequency (VLF) Test Sets Mobile & Fixed Location.
There are 33 AC High Voltage test sets in Substation Operations that are used for distribution feeder processing. We expect to have ~~35~~ 34 AC sets operational by year end–2018. We are finishing up the transition from installing AC High Voltage Test Sets (HVTS) to AC/DC Combination Test Sets.
AC/DC Combination Test Sets
We are installing AC/DC Combination Test Sets at a rate of 2-3 per year. This will alleviate the need to purchase and install separate AC and DC units.

Justification Summary:
Currently, we need to use both an AC test set and a DC test set to process feeders. Maintaining both AC and DC test sets in a station is difficult, as there is insufficient space to house these units. Our goal is to move to a dual function test set and place these sets in networks that have had 80% of the paper cable replaced. We are working with test set manufacturers to develop a dual function test set that will give us the AC & DC capability to perform hi-pots, fault conditioning and fault locating in one unit, thus enabling us to perform all feeder processing activities with a single test set. We have tested and accepted the first manufactured prototype. We are starting the purchase and installation of these units in stations that still require AC testing capability. We are testing a second prototype from a different manufacturer this year. The prototypes will be placed in service for extended testing to prove the capabilities and resolve any operating issues with the prototypes. We are hopeful that both prototypes will be successful and result in a competitive market. We anticipate receiving manufactured AC/DC combination sets available for installation going forward and are transitioned away from future purchases of AC and DC only test sets.

Supplemental Information:

- Alternatives:
  AC Test Sets - As noted above, we are working to develop an AC/DC test set. This would reduce our overall funding needs for this program, as it would halve the number of test sets that we would be required to purchase and maintain in our stations We will continue to work with the equipment manufacturers to help develop the equipment to serve the company's needs.

  We could also move back to DC hi-pots on our distribution feeders, negating the need to purchase AC hi-pot sets. This alternative is not recommended, as AC hi-pots have proven to be better at detecting incipient faults on solid dielectric feeders and reducing the time to the next in-service failure.

  DC Test Sets - Our primary alternative is to stop replacing DC test sets and continue to repair our problematic sets. This alternative is not recommended. Test set availability is critical to our ability to process feeders expeditiously. Leaving units in place that are likely to break down when called upon to perform will result in an increase in feeder processing times.

- Risk of No Action: Failure to maintain our fleet of test sets will lead to extended feeder processing times, as work will need to be suspended in order to repair defective test sets. If additional feeders open auto while this is happening, customers may experience low voltage conditions, or load shedding could occur.

- Non-financial Benefits: The benefit to keeping the test program current with new technology reduces outage frequency and duration.

- Summary of Financial Benefits (if applicable) and Costs: Financial benefits are realized with the installation of a combination set in a DC position. An AC/DC combination set could be installed in a current DC Set position thereby eliminating the need to purchase additional DC Sets. The cost of purchasing an AC set is $313k and a DC Set is $120K or $433K together. We anticipate an AC/DC combination set will cost between $400 and $450k, but a second manufacturer will affect costs through increased competition. We do expect there will be cost avoidance savings where a DC set is directly replaced by an AC/DC combination set, as shown below:
  - Cost to install a separate Test Bus $300 - $500k
  - Cost to build a Test facility $700 - $1,300k

  Technical Evaluation/Analysis: DC high pot testing is destructive in solid dielectric cables which could result in cable degradation affecting their long term reliability. During our evaluation of the AC VLF (Very Low Frequency) testing, we had found that after a feeder that passes AC VLF testing stayed almost twice as long in service compared to when the feeder passed a DC high pot test. AC VLF is also a more effective test for solid dielectric cables and it detects incipient cable faults earlier than DC.

- Project Relationships (if applicable): We have a Public Service Commission (PSC) obligation to replace the amount of Paper Insulated Lead Sheathed Cable (PILC) on the network feeders so that it is less than 10% of total feeder length by 2020. Our current practice requires AC VLF Testing on network feeders where the feeder is 80% or more of solid dielectric extruded-insulation type cables such as ethylene propylene rubber (EPR) or cross-linked polyethylene (XLPE).

- Basis for Estimate: Test set costs are based on historic prices received from vendor quotes or actual purchases made recently. Installation cost estimates are based on Engineering estimates for similar work that has recently been performed.

  The estimated unit purchase cost of the equipment (excluding installation materials, costs, and commissioning tests) is:
  - DC test set: $120k
  - AC VLF test set: $313k
  - AC/DC Test set: $ 400

  Installation costs can range from approximately $215-2000k, depending on the exact scope that is required. Some substations require minimal amount of material and labor while others might require more. The amount of bus sections in a station has a direct correlation to the increase in scope. Typically, a test bus must be installed and its length and complexity greatly affect the cost of the job. In some cases, additional facilities or facility upgrades are required in order to provide adequate space for the test set within the station. We expect the development of the AC/DC test set to minimize the need for additional facilities or facility upgrades.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,010	369	996	597		472
M&S	2,788	319	1,812	1,568		1,035
A/P	682	51	18	10		6
Other	72	34	43	21		19
Overheads	2,039	555	1,042	739		505
Total	**6,591**	**1,328**	**3,911**	**2,936**	**-**	**2,037**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	628	968	1,718	2,558	2,542
M&S	307	499	878	1,300	1,300
A/P	46	75	132	195	195
Other	16	24	44	65	63
Overheads	543	934	1,628	2,382	2,400
Total	**1,540**	**2,500**	**4,400**	**6,500**	**6,500**

X	Capital
	O&M

2019 – Central Operations/System & Transmission Operations

Project/Program Title	Joint Replacement Program
Project Manager	Various
Hyperion Project Number	PR.22679448
Status of Project	Ongoing
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Strategic

Work Description:
The work plan is to replace joints on existing transmission feeders that are at risk of failing electrically and/or mechanically and cannot be addressed through routine corrective maintenance. This is a program that will improve the reliability of the transmission system.

The scope for the Transmission Joint Replacement Program targeted approximately one joint replacement each year for the years 2017-2019 and will approximately target two joints per year tin 2020 and beyond. The joints selected for inspection/replacement will be based upon priority (as determined by Transmission Engineering), and feeder outage availability. The work plan annual estimated budget of $2.85M per year for the previous years will increase up to $5.7M per year for the years 2020-2023(in order to cover the replacement of two joints each year).

Engineering has developed a prioritized list of transmission feeder joints based on feeder performance and investigations that are being addressed under this program and include:

1. FDR 72 – Manhole M27001 (Replaced)
2. FDR M51 – Manhole M61727
3. FDR 72 – Manhole M26595
4. FDR 71 – Manhole M27001
5. FDR 72 – Manhole M26594
6. FDR 71 – Manhole M26595
7. FDR M52 – Manhole M61736 (Replaced)
8. FDR 71 – Manhole M26594
9. FDR 702 – Manhole M7062 (Replaced)
10. FDR 702 – Manhole M55953
11. FDR 38B05 - Manhole 69594 (Replaced)
12. FDR701 – Manhole M7064 (Replaced)

Future joints will be identified by Engineering for outer years.

Justification Summary:
There have been failure events (both electrical and mechanical) associated with joints on transmission feeders during the last 3-4 years that have motivated investigation into whether similar vulnerabilities exist in other locations. These investigations have identified transmission feeder joints that are at risk of electrical and/or mechanical failures that will adversely affect reliability.

Electrical failures and cable damage encountered on Feeders M51 (2011), 69M05 (2012), 38B05 (2012) and 72 (2014) exhibited root causes that suggested the potential for other locations with similar conditions. The April 2011 failure of Feeder M51 was in a semi-stop joint (on Broadway in Manhattan). The observed failure mechanism led to digital x-ray investigation of other joints of similar design on 345kV Feeders M51 and M52. These x-ray results led to the opening of another semi-stop joint on Feeder M51 in March of 2012 to determine if similar damage occurred; significant damage was found, which led to the semi-stop joint's proactive replacement with two buried joints and a cable insert. The failure of High Pressure Gas Filled (HPGF) Feeder 69M05 in manhole M58297 led to investigation of other 69kV feeders with similar joint casing configurations that could have inadequate joint support. The further investigations of 69kV feeders resulted in a joint opening on Feeder 69M06; significant damage was found and that led to the proactive replacement of the joint with two joints and a cable insert. Failures on 138kV Feeder 38B05 and 345kV Feeder 72 were deemed to be due to shielding damage and splice connector vulnerabilities that led to similar x-ray investigation and joint openings, and subsequent joint replacements.

Compromised pipe integrity due to loss of wall thickness has led to many leaks on various High Pressure Fluid-Filled (HPFF) transmission feeders in manholes. Pipe integrity is maintained by pipe coatings and, in buried sections, cathodic protection. Cathodic protection is ineffective in manholes due to the absence of surrounding fill material to act as an "electrochemical cell" allowing the flow of cathodic protection current. Thus, compromised pipe coating in manholes has an increased likelihood of developing leaks. The high leak rate of some of these events can result in a loss of feeder pressure sufficient to require that the feeder be removed from service to maintain its dielectric integrity and to make necessary repairs. Repeated corrosion issues, feeder leaks, and complex repair solutions on joint casings and auxiliary piping systems in certain locations have led to conditions that can no longer be addressed with corrective maintenance. These locations exhibit leaks that have a significant impact on feeder availability- and thus overall system reliability- as leaks can necessitate emergency de-energization of the associated feeders. Engineering inspections have led to the identification of multiple locations on 138kV Feeder 702 and 345kV Feeder M51 that require splice joint replacement due to corrosion conditions that are beyond the normal scope of corrective repair.

Based upon these recent developments, this program will target joints on the underground transmission system that exhibit the susceptibility for electrical or mechanical failure. Engineering has developed a prioritized list of suspect transmission feeder joints to be addressed under this program going forward; however, future evaluations may result in an expanded list and a new priority order with which to address them.

Supplemental Information:

- Alternatives: *Perform Corrective Maintenance*: Corrective maintenance cannot address the potential electrical and mechanical failure causes in various transmission splice joints or joint casings that have been identified through engineering inspections because the material conditions require wholesale replacement.

- Risk of No Action: No action on replacing these joints is allowing them to "Run to Failure". This course of action would allow the joints to fail in service, requiring emergency replacement and restoration. This course of action leads to unscheduled outages that may occur during periods of either high demand or concurrent to planned system outages, affecting transmission system reliability and potentially its ability to supply the required load. Unplanned outages may also cause the cancellation of planned outages to perform scheduled reliability work as well as result in increased expenditure on the deployment of emergency resources. See "Risk of No Action" for more detail.

- Non-financial Benefits: The benefits of this program are improved system reliability and a reduction in the likelihood of dielectric fluid leaking to the environment.

- Summary of Financial Benefits (if applicable) and Costs: Prior to 2016, the spend of this ongoing program was swept to QBB feeder failures.

- Technical Evaluation/Analysis: Some recent transmission joint failures have, upon inspection, displayed damage characteristics that indicate the presence of potential common modes of failure that may exist on certain joints on the transmission system. As technology advances and non-destructive inspection methods (including digital x-ray) become more sophisticated, opportunities to identify and proactively address reliability concerns before joint failure are increasing. Issues related to joint movement and the mechanical strength of splice connectors have already been identified as affecting joint reliability. Under this program, these issues and others in the future will continue to be addressed to increase overall system reliability.

- Project Relationships (if applicable): Not applicable.

- Basis for Estimate: The estimate is based on targeting one 345kV joint per year at a projected unit cost of $2.85M per joint replacement.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	558	51	464	1,381		1,400
M&S	60	11	88	185		200
A/P	301	28	464	966		1,000
Other	13	11	33	72		362
Overheads	716	85	505	1,210		1,300
Total	**1,648**	**186**	**1,554**	**3,814**		**4,262**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,421	1,746	1,635	1,729	1,896
M&S	1,785	763	763	988	1,000
A/P	1,248	1,255	1,255	1,610	1,700
Other	259	240	254	312	400
Overheads	213	1,560	1,292	561	704
Total	**4,925**	**5,564**	**5,200**	**5,200**	**5,700**

X	Capital
	O&M

2019 Central Operations/System & Transmission Operations

Project/Program Title	LP Reservoir Replacements Program
Project Manager	Mark Bauer
Hyperion Project Number	PR.22679451
Status of Project	New Program
Estimated Start Date	January 2016
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

<u>Work Description</u>:
This program will upgrade obsolete fluid filled reservoirs with new pre-pressurized reservoirs and associated equipment on the Low Pressure Transmission System. The new reservoir systems will maintain pressurization via gas filled cells that force dielectric fluid into their associated feeders. The systems prioritized for replacement are located at Bruckner, Hellgate, Eastview, and the East River Substations. The work packages under this program were previously included in the Emergent Transmission Reliability Program and funding for that program has been transferred to this program because the need for the work is anticipated over multiple years.

<u>Justification Summary</u>:
In order to maintain the dielectric strength of the cable insulation, low pressure feeders require external pressurization reservoirs that are located near the cable terminations. The older reservoir systems use external gas systems to maintain internal pressure for subsequent supply of their associated low pressure feeders. The ability to maintain pressure and dielectric strength in these low pressure feeders is essential to keeping them reliably energized.

Many of the older externally pressurized reservoir systems have deteriorated and leak to the point that they are no longer reliable. The current reservoir systems have deteriorated, are prone to leaks, and are obsolete, so they can no longer be easily repaired or replaced in kind. The dielectric fluid leaks from these systems have an adverse impact on the environment. The repair activities required for these leaks are labor intensive and require feeder outages in order to complete. Replacement parts for many of these systems are no longer available.

The upgrade of the externally pressurized reservoir systems is necessary to maintain the reliability of the feeders they service.

<u>Supplemental Information</u>:

- <u>Alternatives</u>: One alternative to this project is to continue to perform corrective maintenance. This alternative will require feeder outages to address deterioration and leaks as they arise. This alternative would address existing leaks and other material deficiencies but would not prevent future ones from occurring. Outages may become more frequent with this alternative and impact feeder availability and reliability.

- <u>Risk of No Action</u>: If this project is not completed, unscheduled feeder outages may become more frequent which would adversely affect reliability.

- Non-financial Benefits: Improved environmental performance is the expected non-financial benefit of completing the projects under the ongoing program.

- Summary of Financial Benefits (if applicable) and Costs: Not applicable.

- Technical Evaluation/Analysis: Not applicable

- Project Relationships (if applicable): Not applicable.

- Basis for Estimate: The funding level in this program was based on performing approximately one to two upgrades each year. The cost of each upgrade is assumed to be approximately equal to that of a completed job of similar scope in the past.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	344	162	10	430		833
M&S	125	40	0	36		177
A/P	32	16	0	6		73
Other	14	6	0	9		25
Overheads	1,418	654	15	353		592
Total	**1,933**	**878**	**25**	**834**	**N/A**	**1,700**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	400	375	500	935	935
M&S	75	212	934	450	450
A/P	36	27	50	50	0
Other	61	323	275	176	216
Overheads	328	459	741	889	899
Total	**900**	**1,396**	**2,500**	**2,500**	**2,500**

X	Capital
	O&M

2022– Central Operations/ Substation Operations.

Project/Program Title	Mobile Control Center
Project Manager	Jim Mooney
Hyperion Project Number	PR.22698518
Status of Project	Planning – Awaiting appropriation
Estimated Start Date	September 30, 2017
Estimated Completion Date	December 2022
Work Plan Category	Strategic

Work Description:
This project will provide a mobile Energy Control Center which can be deployed to one of multiple locations in the event of an Electromagnetic Pulse (EMP), either a High Altitude EMP Pulse (HEMP) or Intentional Electromagnetic Interference (IEMI) attack that disables both the Con Edison's Energy Control Center and the Alternate Energy Control Center (ECC and AECC). The HEMP Hardened Mobile Control Center (HMCC) will require the delivery of three tractor trailer enclosures designed to withstand a HEMP pulse or a localized, directed IEMI attack. These enclosures will contain the core operational systems that comprise a Con Edison Control Center: An Energy Management System (EMS), Feeder Management System (FMS), Pi-Historian, Local Area Networks and Communications systems. In addition to the three Mobile enclosures, this project will include the construction of one or more connection points at Con Edison property site(s) remote from the ECC and AECC to provide a quick connection capability to the Verizon and CCTN communications infrastructures.

The Purchase Specifications for this project have been completed and the formal cost estimate has been done. Assuming it can be approved and released to Purchasing by the end of August, we expect to award the contract by October, 2017 and to take delivery of the equipment within 12 to 18 months after award (April, 2018).

Justification Summary:
This project is a natural component of the overall Con Edison strategy for improved resiliency and fast recovery capabilities. Con Edison has taken a leading role within the Utility Industry in developing proactive solutions to improve the overall resiliency of our system and minimize the recovery times required to regain full operational capability following a range of contingency events such as loss of major equipment (transformers, substation switchgear, etc.). The ECC's are essential to system operations and could be targeted using an EMP pulse or IEMI directed energy attack.

I. Background

a. HEMP and IEMI attacks inflict physical damage to sensitive components due to the very large electric fields generated. The copper cabling typically connected to these devices (such as power leads, communications and network cables) provides a coupling mechanism that exposes these devices to large voltage surges. Integrated circuit devices are most susceptible to this kind of damage.

b. Neither the ECC nor the AECC are protected against EMP and IEMI events that could potentially destroy many of the key control center systems and devices such as system servers, network devices and communications equipment. The recovery time required to rebuild the core systems and regain operational capability could be lengthy. It should also be understood that after rebuilding all the damaged systems following an attack, the control center would be just as vulnerable to the same type of attack.

c. Without a functioning Energy Control Center, Con Edison's systems would have to be operated in a minimal, emergency configuration, with limited visibility possibly requiring reducing load and extended outages, while remaining vulnerable to multiple contingencies.

II. Project Effect on Problem or Deficiency

a. The HMCC will be impervious to EMP pulse or IMEI attacks. It is designed to be deployable in less than 8 hours and take over full operation of the Con Edison power system. Additionally, the HMCC will remain fully protected against any follow on EMP and IMEI events even when fully operational.

b. The ability of the HMCC to drastically reduce the recovery time following a damaged or destroyed Control Center from weeks or months to a few hours will greatly mitigate the cascading effects of a prolonged power outage. Many of Con Edison's critical customers such as hospitals and financial centers have emergency backup generation but these are typically limited to 24 hours or less of backup time. A fast recovery solution such as the HMCC will allow Con Edison to restore power to these customers (and to all other customers) before the backup system resources are exhausted.

Supplemental Information:

- Alternatives:

  One alternative approach that was originally considered was to shield the existing AECC. Although this is possible, it represents a considerable challenge as there are a great number of penetration points and the control center core systems are distributed over a large floor plan. The estimated direct cost for shielding the AECC is over \$15 million (translating to a loaded cost of approximately \$30 million). The large number of shield penetrations required into and out of the building and the total volume to be protected also represents a significant ongoing maintenance cost to ensure that shield integrity and performance do not degrade over time.
  It was also decided that the installation of all the shielding and all required building modifications would be too disruptive for too long a period at the ECC and therefore, only the AECC was originally considered for EMP hardening. The cost to shield the ECC was not solicited but is expected to be much higher than the AECC estimate. The cost to shield the ECC was not solicited but is expected to be much higher than the AECC estimate.

  By comparison, the HMCC can be built for about \$15 million (loaded cost) with much better shield integrity, superior performance and improved maintainability.

  A second alternative to this project is to build a new dedicated shielded Energy Control Center. Although we have not generated a cost estimate for this alternative, it is expected it would be much higher than the estimated cost to upgrade the AECC.

  Both alternate solutions listed above would be fixed locations. In addition to the much lower delivered cost of the HMCC solution, the mobility aspect offers additional advantages and flexibility that further justify it as the more desirable option. An EMP or IEMI attack could conceivably affect systems outside of the existing Control Centers on which they depend for operations, such as the Verizon communications infrastructure. Having the ability to connect the

HMCC at pre-built remote locations would allow us to potentially bypass damaged zones of the Verizon system.

- Risk of No Action:
  If the HMCC system is not built, Con Edison's Control Centers will remain vulnerable to EMP and IEMI attacks. If such an attack were to occur, key systems and electronic equipment would be disabled and could cause prolonged outages.

  Cyber-attacks against bulk power providers have occurred in recent years. These types of attacks have demonstrated the effect that extensive power outages can have. The Company has to prepare for the possibility of a more sophisticated attack with longer lasting effects, such as an IEMI or EMP event.

  Recent world events, particularly the advances made by North Korea in nuclear delivery systems and the growing tensions with the United States mean that this scenario is not out of the realm of possibility. Should these events escalate to such an extent, an EMP attack is actually a viable option that would allow a rogue state to inflict significant damage without requiring precision guidance delivery systems. An exoatmospheric nuclear explosion somewhere above the US landmass would be sufficient to cause the kind of damage that the HMCC is designed to protect against.

  The risk from IMEI, also referred to as High Power Microwave (HPM) is also rising. According to a 2008 Congressional Report on the EMP threat:

  "... while HEMP weapons are large in scale and require a nuclear capability along with technology to launch high altitude missiles, HPM weapons are smaller in scale, and can sometimes involve a much lower level of technology, which may be within the capability of some extremist groups or non-state organizations.
  HPM can cause damage to computers similar to HEMP, although the effects are limited to a much smaller area. The technical accessibility, lower cost, and the apparent vulnerability of U.S. civilian electronic equipment could make small-scale HPM weapons attractive for terrorist groups in the future."

- Non-financial Benefits:
  In addition to the large scale mitigation of potentially catastrophic effects resulting from the loss of both Control Centers, as described above, the quick recover capability provided by the HMCC project demonstrates a serious commitment by Con Edison to its customers' safety and security and to National Security overall. Not only that, but it further reinforces Con Edison's clear leadership in taking proactive measures to identify and provide innovative solutions to potential catastrophic events, thus setting an example and showing the way to the rest of the Utility Industry.

- Summary of Financial Benefits (if applicable) and Costs:
  The corporate Cost-Benefit-Analysis has not been done for this project.

- Technical Evaluation/Analysis:
  A formal review of the EMP threat was published in a 2004 and titled: Report of the Commission to Assess the Threat to the United States from Electromagnetic Pulse (EMP) Attack. The Commission was established by Congress in FY2001 after several experts expressed concerns as to the vulnerability of the U.S critical infrastructure to EMP attacks. The commission was re-established again for 2006 – 2007 and issued an update report in 2008.

The Commission's mandate was to assess:

"(1) the nature and magnitude of potential high-altitude EMP threats to the United States from all potentially hostile states or non-state actors that have or could acquire nuclear weapons and ballistic missiles enabling them to perform a high-altitude EMP attack against the United States within the next 15 years;

(2) The vulnerability of United States military and especially civilian systems to an EMP attack, giving special attention to vulnerability of the civilian infrastructure as a matter of emergency preparedness;

(3) the capability of the United States to repair and recover from damage inflicted on United States military and civilian systems by an EMP attack; and

(4) The feasibility and cost of hardening select military and civilian systems against EMP attack."

The Commission was also charged with making recommendations on steps that should be taken by the United States to better protect its military and civilian systems from EMP attack.

The Commission's overall findings are summarized below:

"Several potential adversaries have or can acquire the capability to attack the United States with a high-altitude nuclear weapon-generated electromagnetic pulse (EMP). A determined adversary can achieve an EMP attack capability without having a high level of sophistication.

EMP is one of a small number of threats that can hold our society at risk of catastrophic consequences. EMP will cover the wide geographic region within line of sight to the nuclear weapon. It has the capability to produce significant damage to critical infrastructures and thus to the very fabric of US society, as well as to the ability of the United States and Western nations to project influence and military power.

The common element that can produce such an impact from EMP is primarily electronics, so pervasive in all aspects of our society and military, coupled through critical infrastructures. Our vulnerability is increasing daily as our use of and dependence on electronics continues to grow. The impact of EMP is asymmetric in relation to potential protagonists who are not as dependent on modern electronics.

The current vulnerability of our critical infrastructures can both invite and reward attack if not corrected. Correction is feasible and well within the Nation's means and resources to accomplish."

The following recommendations are included in the Commission's Report and are directly applicable to the Electric Utility industry to mitigate the effects of an EMP attack:

- Planning to carry out a systematic recovery of critical infrastructures
- Protecting key system components needed for power restoration after an attack
- Develop and enable restoration plans that prioritize and emphasize rapid restoration of critical functions and services

One of the underlying assumptions found in the Commission's Report was that Federal Regulations would likely be necessary to encourage industry wide implementation of mitigation

measures against the EMP threat. Such regulations are yet to materialize. However, Con Edison is taking a proactive approach and taking sensible steps to prepare for this threat scenario.
As part of the due diligence and research related to this project, vendors were brought in to assess the feasibility and provide a Rough Order of Magnitude Estimate cost for the alternate solution of hardening the existing control centers against EMP events. The determination was that this would be feasible to do at an estimated direct cost of about $15 million for the AECC. We do not have information as to the level of shield performance that could reasonably be expected from this solution.

Extensive research was done on mobile EMP shielded platforms. Four vendors who build this type of equipment for various branches of the military were visited and provided detailed information on the design, manufacturing and expected performance of these shielded enclosures. In addition, a number of system integrators also familiar with mobile shielded platforms for military applications were also visited. As a result of this research the project team has a clear understanding of the technologies involved and the level of performance to be expected. All vendors assured us that their systems are capable of meeting the shielding performance specifications of MIL-STD-188-125 issued by the Department of Defense. The basic requirements from these specifications call for an 80 dB shield performance over the frequencies of concern. At least three of the manufacturers indicated complete confidence in delivering shield effectiveness values of 100 dB or greater.

The project team also visited Sandia National Laboratories. Sandia was able to validate the preliminary design concepts and provide detailed information on testing procedures that will conclusively demonstrate the ability of the HMCC to survive an EMP pulse unscathed.

Finally, the team visited an actual test facility at Patuxent River Naval Air Station (aka NAS Pax River) where full scale threat level testing of military systems takes place. NAS Pax River performs testing of military tanks, fighter jets, transport planes, and many such large items. The project plans include shipping the HMCC to NAS Pax River to subject the equipment to full threat level pulse tests which would provide absolute proof the HMCC will be safe from EMP attacks and can be depended on in such a scenario.

- Project Relationships:
  Con Edison has developed business continuity plans in the event of High Impact Low Probability (HILP) events such as the loss of communications between both Control Centers and the substations. The HMCC solution provides yet another valuable resource that could be used in such events. The added flexibility of a mobile platform with multiple communications connection points means that we can address a wider range of emergency scenarios.

  Other potential high impact events such as a cyber-attack that disables both Control Centers, or a zero day virus attack can be mitigated using the HMCC depending on the final Concept of Operations and operational procedures adopted by the HMCC owners.

- Basis for Estimate:
  The funding for this project was determined by extensive research with equipment vendors, system integrators, NAS Pax River and Sandia test facilities as well as multiple meetings with internal Con Edison groups and stakeholders who will be needed to support the project.
  Budgetary quotations were solicited and provided by multiple vendors for all major equipment and services. All budgetary quotes were incorporated into the formal appropriation estimate.

Total Funding Level ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	10		324
M&S	-	-	-	-		13
A/P	-	-	-	3,522		3,270
Other	-	-	-	6		17
Overheads	-	-	-	481		(143)
Total	-	-	-	**4,019**	-	**3,481**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	457	-
M&S	-	-	-	57	-
A/P	-	-	-	58	-
Other	-	-	-	40	-
Overheads	-	-	-	388	-
Total	-	-	-	**1,000**	-

X	Capital
	O&M

2019 Capital - Central Operations/System & Transmission Operations

Project/Program Title	Modernization Program CECONY Electric Feeder Structure
Project Manager	Vern Schaffer
Hyperion Project Number	PR.22661748
Status of Project	Ongoing
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Regulatory

Work Description:

The Modernization Program for CECONY's Electric Transmission Feeder Structures is a proactive program that started in 2018 to mitigate concerns regarding transmission structures (manholes) that have been identified as requiring major/non-routine upgrades. These structures contain Transmission Feeder splices along with auxiliary piping and valves. Structural deficiencies (especially at the end walls where the feeder pipes enter the manhole) as well as water entry due to structural issues, jeopardize the integrity of the feeder pipes and lead to dielectric fluid leaks each year. The upgrade entails rebuild of the end walls of the structures, involving rebar, concrete and masonry components, as well as installation of new feeder pipe penetration sleeves and improved penetration seals, along with the associated required excavation, waterproofing, inspection, application of permanent corrosion repairs to the feeder pipes, new pipe coating, structure cover and chimney upgrade (that will reduce water impingement on the feeder pipes) and backfill/restoration tasks. Other deficiencies with the structure will be addressed with a new spray on epoxy coating that will seal the inside of the entire structure after the end wall repair. This will provide a waterproof seal from the floor of the manhole to the manhole casting, preventing ground water from infiltrating and causing corrosion of the feeder pipes. In addition, the waterseal of the floor of the manhole will prevent dielectric fluid from entering the environment (eliminating reportable spills to the New York State DEC). Furthermore new oil minder devices will be installed to alert Transmission Operations of any water or oil that enters the structure. The program will provide increased reliability and extend the useful life of the existing structures and the feeders by making the assets within the structures more efficient and provide for greater long term durability.

Unresolved deficiencies can lead to major system impacts including dielectric fluid leaks that can affect the environment and cause forced transmission feeder outages.

The latest engineering materials include improved pipe penetration seals, epoxy-coated rebar, concrete waterproof membranes, anti-corrosive galvanizing paint over exposed beams and welds and high strength concrete will be incorporated in the protocol for structural modernization.

Justification Summary:

Attention to the deficiencies identified during the Con Edison inspection program will address defects in the structure end wall(s) as well as any deficiencies found on the existing feeder pipes that penetrate the structure end wall.

Supplemental Information:

- Alternatives: No other alternative has been identified.

- Risk of No Action: Not addressing locations with structural or feeder pipe deficiencies will over time cause dielectric fluid leaks from the compromised feeder pipes, possibly leading to environmental impact, and increased spending due to emergency leak response to the leak and system reliability issues caused by forced feeder outages

- Non-financial Benefits: Increase reliability of the Underground Transmission System, extension of the useful life of both the feeder and structure. Eliminate risk of possible environmental contamination from a feeder leak.

- Summary of Financial Benefits (if applicable) and Costs: The cost for 2018 going forward is based on the cost of reconstructing an end wall on a planned basis opposed to an emergency basis (after a leak has occurred): Excavation of one end wall, inspection and repair of the steel feeder pipe and reconstruction of the end wall is approximately $125,000 direct cost. Average Dielectric fluid leak search and remediation is approximately $300,000 direct cost.

- Technical Evaluation/Analysis: Not Applicable

- Project Relationships (if applicable): Structural work must be coordinated between Transmission Operations Construction Department, Substation Operations and System Operations.

Basis for Estimate: Estimated cost to modernize structure and feeder is approximately $400k.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	473	532	530	522	531
M&S	858	852	858	858	858
A/P	239	236	239	239	239
Other	239	236	239	239	239
Overheads	191	120	134	142	134
Total	**2,000**	**1,976**	**2,000**	**2,000**	**2,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Monitoring Device and Application Program
Project Manager	Stan Lewis/Michael Donohue
Hyperion Project Number	PR.22573806
Status of Project	In Progress
Estimated Start Date	10/1/2016
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program focuses on the monitoring of underground structures for energized object and manhole event precursor environmental changes; and, in the case of full sensor devices, visible and non-visible (infrared) inspection and defect detection. An underground structure or any other object may be monitored for evolving manhole events and energized objects through use of an integrated wireless transmitter, signal processor and sensor(s). When measured conditions such as gas concentration, ambient temperature, cable temperature, or voltage exceed a pre-determined value, a local device or remote data post-process alarm would be generated.

The project's plan is to procure and install the hardware and software for approximately 80,000 Structure Observation System (SOS) full sensor devices over a five year period and approximately 170,000 SOS select sensor devices over a twenty year period in underground manholes and service boxes. In general, all structures that have experienced a manhole event, or all structures within elevated Energized Equipment (ENE) generating plates will receive an SOS full sensor device, while all remaining structures will get a SOS select sensor device. At these levels, the program is expected to reduce manhole events by over 10% a year and advance detection of energized objects to a time frame measured in hours.

Additionally, the SOS devices and their associated infrastructure may serve as a platform for newly developed SMART Crabs (Crab with monitoring ability) which would complement and capture the electrical parameters of reliability and safety including current, voltage, and power flow. The SMART crab measured parameters would aid in blown limiter and low voltage condition detection and correction. These SMART crabs would be installed with routine work with particular focus on larger 5 and 7 way crabs. The program would target a deployment of 500 per year starting in 2020.

Justification Summary:
Damage to the secondary system is generally harder to identify compared to the primary system due to the redundancy of the secondary grid and the lack of remote monitoring equipment beyond the network transformer. As a result, adverse conditions are typically not found until they result in a customer outage, manhole event (smoke, fire, and explosion) Carbon Monoxide buildup, or stray voltage condition. Since these conditions can lead to hazards to the public or prolonged outages, maintaining the reliability of the secondary grid is a priority. The sensors would ensure substantial risk reduction by identifying a faulty condition before it manifests into a serious manhole event or contact voltage danger.

Supplemental Information:

Alternatives:
In lieu of a monitoring system, project alternatives would include both reactive and proactive protection mechanisms.

Reactive:

1. Run assets to full life failure, wherein the condition is publically observed, reported, site secured and mitigated
2. Install latched vented covers which will help contain explosive energy from resulting in a projectile
3. Install structure fill which will reduce the energy of an explosion event

Proactive:

1. Increase scope of Secondary Rebuild Program to cover additional structures
2. Continue inspecting structures visually and with thermal imaging to find and correct defects

The structure observation systems common qualities of being simple, unobtrusive, and cost effective now and in any future program scale up are unique among all of the alternatives.

- Risk of No Action:
  By not taking the opportunity to capture a developing cable failure in its infancy, the risk of personal injury, property damage or loss of reliability is increased. Additionally, both reliability and underground inspections are tracked and regulated by the PSC. Failure to maintain minimum threshold levels in both of these metrics would result in the company having to pay fines.

- Non-financial Benefits:
  The primary non-financial benefit of this program is an increase in public and employee safety. Additionally, this program will contribute to a reduction in emergency response time, particularly during peak event periods (such as storms), since fewer emergency events will occur. It will also contribute to a reduction in troubleshooting time since defective equipment will be replaced before creating an energized object which can be time consuming to diagnose.

  Finally, customer satisfaction will be improved by the increased reliability.

- Summary of Financial Benefits (if applicable) and Costs:
  Every event avoided represents an emergency response not performed, an open main not created, and potential property damage and/or injury avoided. Additionally, the increased reliability and inspection rate that will result from this program will lower the Company's exposure to regulatory fines.

- Technical Evaluation/Analysis:
  The generation of combustible gasses, such as CO_2, from the burning of insulation has been well established. The detection of these gasses can be accomplished through electrochemical and Infrared (IR) based gas detectors. Likewise, voltage present on an energized object can also be measured regularly for abnormal conditions. What has changed substantially is the wireless infrastructure from which data can be sent. Current wireless technologies can be deployed cheaply, at low power, and high bandwidth.

- Project Relationships (if applicable):
  - AMI (As a communications platform for SOS devices)

- Secondary Inspection Program (An SOS full sensor could perform elements of an inspection)

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	73		125
M&S	-	-	-	43		143
A/P	-	-	-	10,386		4,090
Other	-	-	-	328		503
Overheads	-	-	-	232		140
Total	**-**	**-**	**-**	**11,062**		**5,000**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	4,536	4,536	4,536	4,536	4,536
A/P	-	-	-	-	-
Other	403	403	403	403	403
Overheads	61	61	61	61	61
Total	**5,000**	**5,000**	**5,000**	**5,000**	**5,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Non-Network Reliability
Project Manager	Timothy Schlauraff
Hyperion Project Number	PR.8ED0501, PR.21525464, PR.21525466, PR.1ED2011
Status of Project	In Progress
Estimated Start Date	2017
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
The Non-Network is comprised of non-network circuits including 4 kV primary grids and 4/13/27 kV autoloops. Their reliability is ranked by standard industry metrics including SAIFI and CAIDI, so that resources can be used to target the worst performing ones. The ranking process takes into consideration the reliability of the segment; as well as dominant failure contributors and produces circuit-specific reliability improvement options and recommendations based on proper cost-benefit studies.

The Company will implement strategies to enhance non-network feeder performance and improve system resiliency during blue sky and overhead storm events. Poorly performing and aged components will be replaced and upgraded to items that are manufactured to the design and performance standards of today.

Improve source reliability
The non-network system is supplied by a combination of underground and aerial feeder cable systems. In areas where poor performing vintages of aerial and underground cable (PILC, Okonite etc.) leave our customers vulnerable to outages, we will proactively replace the cable with more reliable alternatives.

Overhead Network Secondary Rebuild
Portions of certain secondary networks are fed from overhead facilities typically found on non-network feeders. In some cases the poles and conductors are nearing the end of their useful life. Locations will be prioritized for rebuild based on failure rate, age, and pedestrian traffic volume. This work will include pole replacement, re-conducting, and adding additional capacity as required.

Improvement of Non-Network Feeder Reliability via Reconfiguration of Circuit
Individual autoloops performance can be improved through reconfiguration, minimizing spur size and the addition of segments through the installation of new poles, wire and switches.

Individual 4kV feeders' performance can be improved through reconfiguration, minimizing spur size, addition of automated emergency ties and the addition of segments through the installation of new poles, wire and switches.

Improve Resilience due to Significant Weather Events
There were two consecutive nor'easter storms in March of 2018 that impacted the Con Edison's service territory. Winds from these event were significant with peak sustained winds lasting for more than 36 hours. These storms caused devastating damage to our overhead electrical systems across our service territory. The Company conducted a post storm Quinn and Riley review, issued a report with findings.

Based upon these findings, the Company will initiate the following projects to further enhance the resilience of its non-network circuits.

Open Wire Cable Replacement – Replace portions of the open wire system, particularly long spans (greater than 1000') with no load and single phase load with aerial and/or Spacer cable.

Targeted Autoloops

Bedford, Briarcliff, Byram, Sprout, Meetinghouse, New Castle, Tarrytown and Windmill 2

Add Breakaway Service Connectors – Install breakaway service connectors to enhance the speed of restoration due to tree damage to a service. Target municipalities with a history of "On and Off" the Right of Way tree damage.

Target Municipalities

Cortlandt, Yorktown and Peekskill

Enhance Reliability to URD customers- Add additional supply feeder to URD developments with >100 customers where feasible. The additional supply feeder will supply an ATS which will then feed the URD development.

Target URD Developments

Tarrytown, Hamilton, Chappel and Peekskill

Reconfiguration Of 13kV Auto-loops – Extend 13kV distribution feeders and create additional supply sources allowing the splitting of large auto-loops into smaller segments, minimizing the customer impact and allow for quicker restoration should a future event occur. Reviews of outage data indicate a correlation with the length of an auto-loop and the damage incurred during significant weather events.

Target Loops and Municipality

Aqueduct (Yorktown), Quaker (Cortlandt), New Castle (Mt. Kisko), and Mt. Kisko (Mt. Kisko)

Trip Savers – Install fused trip savers on spurs on our primary feeders to minimize the number of customers momentarily interrupted due to damage to the feeder on a given spur. The trip saver will react before the autoloop recloser and attempt to reclose if a momentary fault occurs.

Target Loops

Mt. Kisko and Mt. Hope

Cross-Commodity Undergrounding– Based on a 2013 study, the estimated cost to underground an overhead system would cost approximately $8.5M / mile. In an effort to take advantage of synergies between commodities and limit the disturbances to customers within the municipalities, electric plans to partner with the gas department in a Cross-Commodity bundling of work and convert overhead facilities to underground facilities where feasible.

Target Municipalities

Cortlandt, Yorktown, Peekskill and North Castle

Double Wood Remediation-- Installing new poles is essential to maintaining safe, adequate, and reliable electric service, however, the removal of older, often structurally unsound poles has not kept pace with new installations. One of the main drivers of this issue is that there are multiple companies that attach equipment and conductors to utility poles. In general, the companies need to transfer their attachments in a specific order. If one company fails to complete the transfer in a timely fashion, the process is extended for all connected parties. Another reason is that there are some cases in which the transfers are more complex – specifically riser installations. Primary feeder riser transfers by Con Edison require a feeder outage and the work required during the outage is more extensive than an overhead wire transfer. Factors such as these result in a partial transfer of facilities by utilities and pole attachment entities of all or part of its equipment to the new pole while facilities remain on the old pole. Where transfers are not completed in a reasonable period of time, or never completed, a double pole situation is created.

Based on a survey completed in 2012, there were approximately 17,600 double pole conditions on hand in Con Edison's service region. The cost to correct each situation varies based on the amount of equipment installed at the location. The funding for this program is used to complete all Con Edison work associated with remediating double pole conditions noted in the 2016 survey. In 2016, Con Edison initiated a plan is to reduce the on-hand number of poles down to the normal annual turn-over in a ten year period. This program includes the inspection of approximately 1,760 poles per year through 2026, and update the National Joint Use Notification System (NJUNS). Where work is still pending completion by Con Edison, it is scheduled for completion.

There are multiple entities with pole attachments other than Con Edison and Verizon including New York City Department of Transportation (DOT), New York City FDNY, Time Warner, Cablevision, and other communication companies. In order to remove a pole, each company is required to send a crew to transfer their facilities after a new pole is set. Con Edison, Verizon, and most of the other companies with pole attachments are currently using NJUNS as a means to provide timely notifications to each party attached to a pole when wire and equipment need to be transferred.

<u>Justification Summary</u>:
Customers experience interruptions on average once every 2-3 years discounting storms. Circuits and customers that experience outages on an average higher than the system average are reviewed for potential redesign. The goal of this work is to improve service to the customers on each circuit supplies as measured by SAIFI/CAIDI statistics.
Additionally, on May 25, 2011 the New York State Public Service Commission issued its Order Adopting Implementation of a Standardized Facility and Equipment Transfer Program in Case 08-M-0593. One of the requirements of this order was for pole owners to "to submit a report to Staff, either jointly or if necessary individually, discussing how pole owners propose to reduce the number of double poles currently in existence, describing impediments to reducing the number of existing double poles, and setting forth possible solutions." Con Edison complied and submitted a proposal on January 3, 2012. In the report Con Edison indicated that the extent of the issue could not be quantified and that the annual stray voltage inspection program would be used to assess the issue. Based on information gathered from the inspection program, there are approximately 17,607 double pole conditions in Con Edison's service territory.

<u>Supplemental Information</u>:

- <u>Alternatives</u>:
  The alternative to this reliability program is to respond solely to equipment failures and outages.

- <u>Risk of No Action</u>:
  The overhead system performance will decline and customers will experience less reliable service in select areas. Component failures could potentially injure the public in some cases.

- Non-financial Benefits:
  The risk of injury to the public will be decreased by fewer non-network system component failures and fewer areas without lights.
  With the decrease in power outages, customer satisfaction will be enhanced.

- Summary of Financial Benefits (if applicable) and Costs:
  Although difficult to quantify, the benefits of this program include enhanced reliability of the system during a blue sky day and major storm.

- Technical Evaluation/Analysis:
  Each project will be evaluated in terms of improvement to the indices of importance for the system. Any source reinforcement projects will be evaluated in terms of reduced future failure rates for that supply feeder. Any other project will be evaluated in terms of SAIFI/CAIDI improvement.

- Project Relationships (if applicable):

- Basis for Estimate: Historical unit costs.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	878	148	291	1,575		6,569
M&S	1,120	(3)	197	1,281		5,997
A/P	407	67	86	1,106		9,440
Other	-	(8)	-	(8)		94
Overheads	1,369	172	314	1,769		8,567
Total	**3,774**	**376**	**888**	**5,723**		**30,666**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	7,760	6,731	7,993	6,328	6,166
M&S	7,048	6,113	7,259	5,747	5,600
A/P	9,110	7,902	9,383	7,428	7,238
Other	64	56	66	52	51
Overheads	10,000	8,674	10,299	8,154	7,945
Total	**33,982**	**29,476**	**35,000**	**27,708**	**27,000**

X	Capital
	O&M

2019 Capital - Central Operations/System & Transmission Operations

Project/Program Title	Operations Network For EMS
Project Manager	David Wernsing
Hyperion Project Number	PR.23184321
Status of Project	Ongoing
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Operationally Required

Work Description:

This program's focus is improvement and expansion of the network infrastructure at the primary and alternate Energy Control Centers to support operational reliability of System Operation's computer systems. As necessary, firewalls, routers, and switches will be replaced and/or additional devices will be added. The network infrastructure will periodically be evaluated and enhanced to support data transmission at wider bandwidths. Systems will also be identified and added to facilitate centralized management and process automation to improve support efficiency. This project will allow us to implement best security practices and meet the North American Electric Reliability Corporation (NERC) Cyber Security (CIP) Standards.

To take advantage of server virtualization, a Storage Area Network (SAN) will be installed and several SAN storage arrays identified and procured. In addition, Microsoft Windows 2012 Failover clusters will be installed in several security zones to provide High Availability (HA) Hyper-V virtual servers. These installations will be expanded each year as more of our infrastructure and Operational systems start taking advantage of virtualization.

The infrastructure supporting the connections between the ECC and AECC has been enhanced to take full advantage of virtualization. Enhancements will be installed in each control center to support internet Small Computer System Interface (iSCSI) storage networks and virtual server clusters for automated process migration. The infrastructure supporting communication with our Remote Terminal Units (RTU), Electric Operations Electric Control Centers, and the New York Independent System Operator (NYISO) will be enhanced to support modern communication protocols such as Secure-Inter-Control Center Communications Protocol (ICCP) and Multi-Protocol Label Switching (MPLS). Part of the planning and specification will include plans to replace the current network switches, routers, and infrastructure in support of these efforts.

Justification Summary:

Increased demands on the existing network infrastructure, increased firewall protection, and more communications between application systems require continued improvement. In order to take advantage of newer technologies, supporting infrastructure needs to be deployed that will accommodate increased data transfer. Additionally, the infrastructure and support systems that control and monitor the operational networks and systems require technology uplifts every three to five years to remain supportable through the manufacturer.

As more network-based systems are installed, data traffic on the existing infrastructure is subject to bottlenecks. To maintain the integrity of the network and to provide uninterrupted system communication for operational systems, these enhancements need to be pursued. The addition of a fully functional and independent alternate control center requires the ability to manage all IT resources from either center, which, in addition to expanding regulatory requirements, requires the centralized management, monitoring, and process automation to meet operational commitments.

Supplemental Information:

- Alternatives: None. The project is following industry and corporate standards.
- Risk of No Action: The risk of no action is exposure to not meeting operational or regulatory requirements because the infrastructure is unable to support the required bandwidth, process monitoring, or security obligations. Additionally, compliance with several other NERC CIP Standards and NERC Reliability Standards would be jeopardized if the network infrastructure does not keep pace with technological advancements.
- Non-financial Benefits: Enhanced reliability and regulatory compliance capabilities.
- Summary of Financial Benefits (if applicable) and Costs: Not Applicable
- Technical Evaluation/Analysis: Not Applicable
- Project Relationships (if applicable): This project is to provide the network infrastructure for all System Operation cyber assets and is thereby related to all System Operation projects using network resources. Examples include; Cyber Security; EMS Reliability AECC and ECC; EMS Replacement AECC and ECC.
- Basis for Estimate: Historical spending, identified enhancements, and vendor estimates.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	6	32	23	51		30
M&S	-	-	-	-		-
A/P	137	602	91	111		150
Other	-	-	-	-		-
Overheads	13	41	16	29		30
Total	**156**	**675**	**130**	**191**	**-**	**210**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	90	90	90	90	90
M&S	-	-	-	-	-
A/P	142	146	153	153	153
Other	12	13	13	13	13
Overheads	45	44	44	44	44
Total	**289**	**293**	**300**	**300**	**300**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Osmose
Project Manager	Kevin Oehlmann
Hyperion Project Number	PR.5ED0191, PR.5ED4201, PR.5ED1281, PR.5ED3211, PR.5ED2201
Status of Project	In Progress
Estimated Start Date	Continuous
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program funds the installation of "C-trusses" or braces to secure utility poles where decreased strength requires the installation of additional support. The C-truss provides external bracing for poles that do not pose an immediate threat to the safety of the public or the distribution system. The five-year average for poles requiring additional support is approximately 353 units per year.

Justification Summary:
Pole inspections are performed to ensure the reliability of installed poles and safety of the public as referenced Con Edison's specification EO-10345, Inspection and Ground line Treatment of Standing Wood Poles. As inspections are completed and it is determined that pole does not have the required strength, they either must be replaced or restored to full strength and functionality by way of C-trussing. Installing C-trusses defers the need to replace poles and create a double pole condition. It is more cost effective as compared to pole replacement.

Supplemental Information:

- Alternatives: An alternative to implementing the Osmose (C-truss) program is to replace a pole in its entirety. This would be done when the pole structure is compromised for reasons such as extreme weather conditions or decaying composition due to old age. In addition, replacing poles in their entirety is more time consuming and expends more labor than simply reinforcing a pole with a truss. It also creates a "double pole" condition at the pole location until all parties attached to the old pole transfer their equipment and the old pole is removed. Utilizing a C-truss, the useful lifespan of a pole can be significantly extended at a lower total cost.

- Risk of No Action:
Pole failures could adversely impact public safety and system reliability. Additionally, there would be a greater cost for emergency response after a pole failure as compared to planned pre-emptive work.

- Non-financial Benefits: Reinforcing poles with reduced strength improves system reliability as weakened poles are more susceptible to breaking and falling, which can pull down overhead cable and cause outages. Pole reinforcement has the potential to positively impact the Company's reliability metrics (SAIFI and CAIDI). Moreover, downed wires and poles create public safety concerns making C-truss reinforcement a viable program in enhancing public safety.

- Summary of Financial Benefits (if applicable) and Costs:
  Reinforcing weakened poles will help reduce the Company's exposure to liability.

- Technical Evaluation/Analysis:
  Pole reinforcement has been used successfully to restore strength to decayed poles for more than 50 years. The devices restore code-mandated strength and add years of service life to the pole. Transverse and longitudinal loads applied to reinforced poles are applied to the truss instead of the pole. This allows the load to circumvent the aged portion of the pole at the ground line.

- Project Relationships (if applicable):
  None

- Basis for Estimate:
  The basis for the estimates use in this program is based on the historical unit cost for C-truss installations.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	363	317	424	556		502
M&S	70	138	111	43		136
A/P	378	303	469	311		443
Other	-	30	22	2		6
Overheads	489	470	482	454		448
Total	**1,300**	**1,258**	**1,508**	**1,366**		**1,536**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	538	558	576	573	591
M&S	281	284	283	278	268
A/P	469	462	461	454	436
Other	426	427	438	442	438
Overheads	686	602	575	586	600
Total	**2,400**	**2,333**	**2,333**	**2,333**	**2,333**

X	Capital
	O&M

2019 – Central Operations/Substation Operations

Project/Program Title	Other Capital Equipment Upgrades.
Project Manager	Dan Brown
Hyperion Project Number	PR.0ES3200
Status of Project	In-Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
This program funds various small and limited scope projects that are not covered by other capital program lines. Modifications and upgrades at individual substations for equipment related upgrades are generally executed as required. Minor equipment improvements, such as the following, are covered under this program:

- Cable Trough Replacement
- Replacement of Potential Transformers and other instrument transformers
- Barksdale Switch Installations
- Bird Netting in Transformer Vaults
- Emergency Diesel Generator Repairs/Upgrades

Current Status 2019: The following projects represent a sample of Other Capital Equipment Upgrade Projects identified as candidates to be funded via this program in 2019.

1. Various – Start Piping Modification for Emergency Diesel Generators
2. Various – Diesel Generator Emergency Stop Pushbutton Installation
3. West 42nd Street/Plymouth Street – Start Exhaust Tubes replacement in Various Circuit Switchers
4. Various – Start Barksdale Switch Installations
5. Various – Platform Self Closing gates
6. Avenue A – Bird Netting Transformer Vaults

Projected 2020 – 2022 Projects: The following projects are a sample of Other Capital Equipment Upgrade Projects identified as candidates to be funded via this program in 2020.

1. Various – Continue Piping Modification for Emergency Diesel Generators (multi-year Project)
2. West 42nd Street/Plymouth Street – Replace Exhaust Tubes in Various Circuit Switchers (multi-year project)
3. Various – Continue Barksdale Switch Installations (multi-year project)
4. Parkchester/Tremont – Bird Netting Transformer Vaults
5. Corona/East River – Install/Replace Guardrail & Fall Arrest Systems
6. Vernon – Replace Insulators and Sagging Runs
7. Ossining - Replace Tap Changer Controls TR1
8. Vernon - Provide a Supply from the Network to Allow the Removal of the L&P Supply from RAV Unit

Other projects similar to those listed above make up the entire candidate listing. We expect additional projects to emerge and be part of future candidate listings.

Justification Summary:
This program is required to fund small projects that are not covered by other capital programs. These projects are necessary to improve the substation facilities and the electrical system.

Supplemental Information:

- Alternatives: The alternative is to take no action. This is not recommended as the improvements described are necessary to maintain both facilities and equipment in working order. Taking no action will increase the chance of degradation of all components requiring periodic and corrective maintenance. This would eventually lead to potential hazardous conditions that could impact equipment reliability and the safety of company personnel as well as the general public.

- Risk of No Action: The risk of no action is that the continued degradation of equipment and facilities could lead to potentially hazardous conditions. These conditions could impact equipment reliability and the safety of company personnel and the public.

- Non-financial Benefits:
    - Enhances the safety of company personnel and the public.
    - Minimizes degradation of equipment and facilities which could lead to potentially hazardous conditions impacting equipment reliability

- Summary of Financial Benefits (if applicable) and Costs: NA

- Technical Evaluation/Analysis: NA

- Project Relationships (if applicable): Some projects such as Barksdale switch installations, replacement of potential transformers or Coupling Capacitor Potential Devices (CCPD's) require outages on the system, and these outages are subject to system conditions.

- Basis for Estimate: The basis for the funding request moving forward is the historic annual spend for work done under this ongoing program, adjusted downward slightly to allow funding to be diverted to other, higher priority work.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,099	283	844	1,402		655
M&S	289	287	979	253		392
A/P	381	197	88	629		542
Other	55	62	98	197		102
Overheads	1,305	532	926	1366		649
Total	**3,130**	**1,362**	**2,934**	**3,848**		**2,340**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	485	787	723	726	1,080
M&S	251	377	352	352	523
A/P	266	406	375	375	558
Other	67	88	93	99	133
Overheads	496	880	801	791	1,191
Total	**1,565**	**2,538**	**$2,343**	**$2,343**	**3,485**

X	Capital
	O&M

2019 Capital - Central Operations/System & Transmission

Project/Program Title	Overhead Transmission Structures Program
Project Manager	Mark Davis
Hyperion Project Number	PR.22679501
Status of Project	Ongoing
Estimated Start Date	January 2017
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
This project provides for upgrades on specific 345 kV steel lattice towers selected based on feeder criticality, engineering analysis and accessibility. An analysis is performed on a corridor-by-corridor basis with priority given to critical corridors as specified by System Operations and Transmission Planning. Reinforcement of these overhead towers will increase structural capacity and system reliability and prevent tower cascading. The first priority was given to the approximately two-mile corridor south of Millwood Substation consisting of six 345kV circuits known as the "Six Circuits South of Millwood". The current design criteria for this program is to induce a full broken wire scenario on the structure and reinforce it to become a dead-end structure for that criteria.

This program will continue to identify potential failure scenarios that will be used to prioritize other work to be done in future years. Based on this ongoing evaluation, selective tower element reinforcement projects will be identified that mitigate the possibility of tower failures or severe cascading events.

High-level schedule*: Upgrade as follows*;

- W89/W90 on the D-line in 2019
- W82/W85 on the K-line in 2020
- Y86/Y87 on the D-Line in 2021
- F38/F39 on the D-Line in 2022
- W82/W85 on the K-Line in 2023
- Y86/Y87 on the D-Line in 2024

Addressing these concerns will also reduce the likelihood of potential failures during severe weather conditions.

Justification Summary:
This program is necessary because upgrading existing structures will reduce potential tower failures, thus reducing operating constraints and improving reliability. Through selective reinforcement of towers, this project will decrease the likelihood and impact of multiple failures resulting from tower cascading (when an event causes the conductors on one side of a tower to be cut and the ensuing uneven force on the tower pulls down the structure; this cascades from tower to tower).

Supplemental Information:

- Alternatives: The alternative is to not upgrade structures and accept the risk of potential cascading in the event of a tower failure which could result in lengthy outages.

- Risk of No Action: Potential cascading in the event of a tower failure, which could result in lengthy outages. Con Edison currently has ten Linsey portable emergency transmission towers, two 120ft wooden poles, and eleven 100ft wooden poles available for emergency use following the loss of a tower or multiple towers. This discretionary program addresses the higher risk areas of the overhead transmission system.

- Non-financial Benefits: Non-financial benefits include employee safety, increased reliability, and increased security in the more vulnerable areas of the overhead transmission system.

- Summary of Financial Benefits (if applicable) and Costs: Not applicable.

- Technical Evaluation/Analysis: Structural analysis of the existing towers is currently on-going with support from consultants and company engineers. Engineering analysis for prioritizing additional tower upgrades on other overhead lines is in progress.

- Project Relationships (if applicable): Not applicable.

- Basis for Estimate: The estimate request is based on historical spending. Work scopes for identified projects vary from year to year based on field conditions (topographical terrain, as-found structure condition) for the targeted work locations.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	706	1,237	1,123	64		587
M&S	407	305	11	6		71
A/P	16	202	38	236		15
Other	1,555	819	213	8		6
Overheads	848	1,648	949	74		367
Total	**3,532**	**4,211**	**2,236**	**372**		**1,046**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	530	602	605	520	628
M&S	-	350	350	250	400
A/P	410	424	424	400	500
Other	600	226	236	250	300
Overheads	384	349	385	280	172
Total	**1,924**	**1,950**	**2,000**	**1,700**	**2,000**

X	Capital
	O&M

2021 – Central Operations/System & Transmission Operations

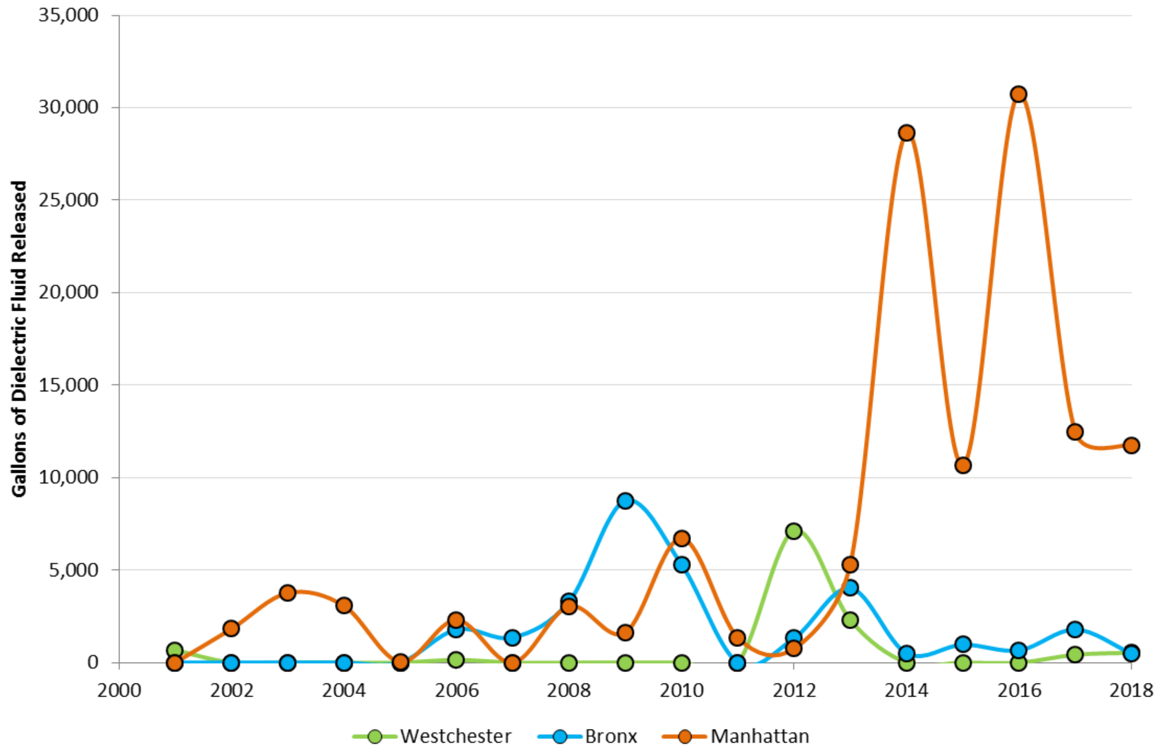
Project/Program Title	Partial Replacement of Feeders M51 and M52
Project Manager	Mark Bauer
Hyperion Project Number	PR.23289178
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2025
Work Plan Category	Strategic

Work Description:
This project will replace the Manhattan portion of 345kV feeders M51 and M52 with new cables along a new route. Feeders M51 and M52 run between Sprainbrook Substation in Yonkers, through the Bronx, to W49th Street Substation in Manhattan. This project will replace approximately 8 miles of high pressure fluid filled (HPFF) cable with approximately 10-11 miles of cross-linked polyethylene insulated (XLPE) cable along a new route to W49th Street Substation. The project will also install a gas insulated substation (GIS) to transition between the HPFF and XLPE cable sections. The XLPE portion will be a combination of submarine cable and underground cable in duct banks. The estimated cost for the project is $675M. The Manhattan portion of M51 and M52 has been prioritized for replacement due to significant leak history and life cycle cost considerations. Engineering activities for this project will begin in 2021 and construction is estimated to be completed by the end of 2025.

Justification Summary:
Feeders M51 and M52 were installed in 1974. The feeder routes are each over 17 miles long and go through significant portions of Westchester, the Bronx, and Manhattan. Within the past ten years, these feeders have seen over 180 leaks totaling 140k gallons of dielectric fluid released. This figure represents roughly 18% of the total volume of dielectric fluid contained in the two feeders. The Pipe Enhancement Program, which restores the integrity of the cable pipe, has been the primary method used to reduce the frequency of dielectric fluid leaks. Although Pipe Enhancement has reduced the frequency of dielectric fluid leaks in many areas, the Manhattan portion of feeders M51 and M52 has presented unique challenges that have affected the longevity of this solution. Due to the risks presented by instances of stray electrical current, submarine crossings, and overall maintenance burden, the Manhattan portion of feeders M51 and M52 needs to be replaced with XLPE cable.

Since 2009 through October of 2018, the majority of leaks on feeders M51 and M52 have occurred in Manhattan and along Sedgwick Avenue in the Bronx. During this time, these areas experienced 193 leaks totaling 139K gallons of dielectric fluid released. Over the years, 8K and 17K trench feet of Pipe Enhancement have been completed in Manhattan and along Sedgwick Avenue, respectively. Pipe Enhancement has been effective in reducing leaks along Sedgwick Avenue; the response in Manhattan has not been quite as successful, however as demonstrated by the figure below.

Figure 1: Gallons of Dielectric Fluid Released by Borough by Year



The Manhattan portion of feeders M51 and M52 along the Harlem River Drive has been particularly challenging with 28,161 gallons in that section alone leaked from 2015 to 2018, despite over 5,000 trench feet of Pipe Enhancement being completed in the same timeframe.

Stray DC electrical current along the Harlem River Drive from transit systems has accelerated corrosion, deteriorated the pipes, and caused feeder leaks in sections that have already undergone Pipe Enhancement. After numerous leaks along the Harlem River Drive, an extensive study, testing, and the installation of voltage recorders helped identify the presence of stray current. One of the sources of stray current was narrowed to an MTA facility and new rail insulating joints were installed to mitigate the issue. An additional source was found to be a MetroNorth facility in the Bronx, where defective rail isolation joints were found and subsequently replaced to interrupt the stray current return path. Further refurbishment of areas that were heavily affected by stray current and have exhibited dielectric fluid leaks is still being pursued, including the potential installation of carbon fiber wrap in these areas. It is not possible to know the full extent of the pipe damage caused by stray current without fully excavating and visually inspecting the Harlem River Drive portion of feeders M51 and M52. Given the proximity of the area affected by stray current to the Harlem River itself, there is a risk that the submarine crossing section was also affected. To date, no leaks have occurred in the submarine portion of either M51 or M52.

Feeders M51 and M52, and the Manhattan portion in particular, present a maintenance burden for the Company. The feeders average 1,500 to 2,000 hours per year in corrective maintenance, which is 3.5-5 standard deviations above the mean for the rest of the 345kV feeder population. Over the past ten years, about 60% of this work took place in the Manhattan portion, and over the past few years this figure is closer to 80%. Leak remediation has also required a considerable amount of funding – averaging around $5M a year or $350K per section leak. The Manhattan portion of the feeders makes up approximately 75% of the yearly costs for leaks.

Replacement of the Manhattan portions of M51 and M52 with XLPE cable would eliminate dielectric fluid leaks in the worst performing sections of the feeders and eliminate any environmental risks associated with the Harlem River crossing. The elimination of the maintenance and emergency response burden associated with the Manhattan portion of the feeders will reduce expenses and free up Company resources for other work on the system.

Supplemental Information:

- Alternatives: Two additional alternatives were looked at for replacement of this project:
  - Replacing M51 and M52 with approximately 8 miles of XLPE in new lanes that follow the route of the existing feeders from the Sedgewick PURS site to W49th St Substation. At Sedgewick this would include two new 345kV disconnect switches with ground switches, a new pumping plant, and two incoming and outgoing sets of SF_6 potheads. W49th Street includes two new sets of SF_6 potheads for the incoming feeders. The estimated cost for this project is $590M and it is expected that this option would have the longest study and route construction time. Some advantages to this option are that it is cheaper than the submarine option. The major challenge with this option is that finding routes for the feeders through Manhattan streets will be difficult.
  - Performing Pipe Enhancement along the whole Manhattan portion with Carbon Fiber Wrap. The estimated cost for this project would be upwards of $700M. The advantage to this option is that new construction is avoided and the Company essentially "replaces the pipe in place." This still does not, however, reduce the dielectric footprint and it also does not address the river crossing. Permitting may also be an issue in congested areas. The duration of work would likely extend over several years due to the labor-intensive nature of the work over such a large portion of the feeder.
  - The third option explored for this project is the use of triplex, XLPE cable in the existing pipe, which is being developed under an R&D project. Although this option avoids most of the trenching costs that would normally be required, outage constraints would extend the schedule considerably. The use of this type of cable in pipe would also require a significant de-rating of the two circuits from the current rating. The magnitude of the de-rate might require the Company to submit the project to the NYISO Interconnection queue for approval and may require other system upgrades to compensate for the loss of capacity.

- <u>Risk of No Action</u>: Without action, there is a risk that leaks along Harlem River Drive will continue to occur, or new areas along this feeder may also start to experience stray current and/or leak issues. Trending shows that leaks are continuing to occur more and more frequently along the Manhattan portion of these feeders. Without proactive remediation, Con Edison will continually be responding to leaks along these feeders with the risk that the feeder will need to be replaced in the future anyway.

- <u>Non-Financial Benefits</u>: Protection of the environment and increased reliability are added benefits. Replacement of the circuits with XLPE reduces the dielectric inventory and reduces the risk of a leak into an environmentally sensitive area. The elimination of the corrective maintenance and leak response labor hours associated with the Manhattan portion of feeders M51 and M52 will free up Company personnel to focus efforts on other parts of the system.

- Summary of Financial Benefits (if applicable) and Costs: In Company labor alone, Con Edison is spending 150-200 times more on each of M51 and M52 than other 345 circuits. Typical spend for Con Edison corrective maintenance on these circuits can range from $50K to over $500K, averaging about $350K per year, the bulk of which is in the portion that will be replaced. Including costs for leaks and emergencies, it is not unusual for Con Edison to spend several million dollars in expense on these circuits, just in Manhattan. Based on the trend of frequency of leaks, it is not unlikely that these circuits will continue to cost several million dollars per year in the current configuration .

- Technical Evaluation/Analysis: By eliminating the Manhattan portion of these feeders, approximately 340K gallons of dielectric fluid will be eliminated from the system, reducing the potential for an environmental event in an area prone to leaks due to the problems caused by disbanded coating. In addition, these feeder leaks impose a risk to system reliability if the feeder needs to be taken out of service to repair the leak. If the leak is severe enough and pressure cannot be maintained, it could lead to an electrical failure.

- Project Relationships (if applicable): None.

- Basis for Estimate: The funding request for this project is based on conceptual scope and an order of magnitude estimate.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	9,682	24,208	24,000
M&S	-	-	11,985	29,905	28,296
A/P	-	-	19,246	48,164	48,164
Other	-	-	6,542	14,796	9,811
Overheads	-	-	19,845	51,177	57,979
Total	-	-	**67,300**	**168,250**	**168,250**

X	Capital
	O&M

2019 – Central Operations / Substation Operations.

Project/Program Title	Pothead Pressure Alarms
Project Manager	Dan Brown.
Hyperion Project Number	PR.22100446
Status of Project	Engineering/Planning
Estimated Start Date	2019
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

The Electric Power Research Institute (EPRI) is developing wireless sensors to be used in a dielectric fluid pressure monitoring system. This system is specifically intended to be installed at Transmission Feeder potheads, where currently only general high/low pressure alarms exist. The advantages of this type of monitoring system include: knowledge and remote indication of actual pressure readings, low power consumption, relatively low cost components, high speed inspection, and long inspection distances without significant trenching and cable installation. The system concept has been proven on two feeders, 38W10 and 99153M, at Dunwoodie Substation, however additional development of the concept is needed to create a system that can be integrated into existing company infrastructure and provide all the intended benefits. This second phase will include:

- Task 1: Develop wireless pressure sensors with increased server update rate for near real time data availability
- Task 2: Address and implement wireless cyber security for the system
- Task 3: Implement variable data rates and alarming during emergency conditions
- Task 4: Demonstrate pressure sensors at Jamaica Substation (Feeders 18001 and 18002), W49th St. Substation.
- Task 5: Build a knowledge based notification and visualization system

Once the system is determined to be feasible and provide the expected benefits, the technology can be commercialized for implementation throughout the Con Edison system based on a prioritization plan.

Justification Summary:

As a result of the June 2010 Dunwoodie fire, Con Edison lost one pumping plant, which subsequently led to seven 345 kV feeders connected to the substation ring bus tripping. The pumping plant fire directly led to depressurization of four 345 kV feeders, causing two of the four to fail catastrophically. The other two feeders had other means of maintaining minimum pressure long enough for the feeders to be taken out of service prior to failing. There is currently no means of remotely monitoring feeder pothead pressures. The existing alarm system only generates a high/low pressure category alarm, which has to be locally verified by the operator reading a pressure gauge at the potheads.

Currently there can be a significant delay before the substation operator can physically read and verify feeder pressure after receiving a pothead pressure alarm. Remote pressure monitoring would allow for a quick way to verify pressure alarms and would also allow remote monitoring from the Energy Control Center. For low pressure conditions, quicker notification and verification would allow time to take the feeder out of service prior to failure. This system can also be integrated into a dielectric system visualization and notification system to incorporate field data and system knowledge and create a smart display for the dielectric system.

The capability of detecting the decaying pressure on a feeder can prevent catastrophic failure on the transmission system, as well as provide a means to detect potential feeder leaks. In both cases, this would also prevent or lessen the environmental impact of dielectric fluid release to the environment. This technology can also be used to replace existing "simple" alarm systems, some of which need to be replaced due to their condition.

Supplemental Information:

- Alternatives: Literature search and discussions with EPRI have indicated that no similar work has been done.

- Risk of No Action: Given the consequences, including enterprise risks that might arise, by not doing the project/program. Quantify the risks, if applicable.

- Non-financial Benefits:
  - Maintain the reliability of our HPFF (high-pressure, fluid-filled) transmission system, reduce potential environmental impact, and provide real time remote monitoring

  - Improve the quality of our normal operating practices and aid in emergency response

- Summary of Financial Benefits (if applicable) and Costs:

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable): N/A

- Basis for Estimate: Order of Magnitude

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	30	30	32	30	30
M&S	36	34	33	34	34
A/P	34	32	32	33	32
Other	8	8	7	8	8
Overheads	42	46	46	45	46
Total	**150**	**150**	**150**	**150**	**150**

X	Capital
	O&M

2020 – Electrical Operations

Project/Program Title	Pressure, Temperature and Oil Sensors
Project Manager	Jane Shin
Hyperion Project Number	PR.5ED1171, PR.5ED3161, PR.22011059, PR.22975789
Status of Project	In Progress
Estimated Start Date	2010
Estimated Completion Date	2020
Work Plan Category	Strategic

Work Description:
This program funds the installation of Pressure, Temperature, and Oil level (PTO) sensors on Con Edison's network distribution transformers. As of January 1, 2018, approximately 22,000 network transformers had PTO sensors installed. Con Edison crews are expected to install approximately 1,700 additional PTO sensors in 2018 for a total of 23,700 installed. All 25,641 network transformers connected to the Remote Monitoring System (RMS) are targeted to have sensors installed by December 2020.

Justification Summary:
In-service transformer failures are a public safety concern, and PTO sensors help mitigate such concerns by identifying a suspect transformer prior to failure. Network transformers used by Con Edison are installed in underground vaults and manholes in public areas.

The PTO program is one of the transformer failure mitigation programs that have contributed to an 80% reduction in transformer failures since 2006. In 2017, approximately 200 transformers were preemptively removed from service due to problems detected via PTO sensors.

Supplemental Information:

- Alternatives:
  Increase Inspection Frequency on Units without Sensors – Halt installation of PTO sensors. To maintain a condition assessment on units without sensors installed similar to those with sensors installed, the frequency of routine physical inspections will need to be increased to detect transformers at risk of failure. More frequent vault inspections will require a significant increase in maintenance costs and provide less information regarding the condition of the transformer.

  Maintain Current Inspection Frequency on Units without Sensors – Cease PTO sensor installation and continue inspecting network transformers at the same rate. Units without PTO sensors installed will be a greater failure risk than units with sensors.

- Risk of No Action:
  When a network transformer fails, there is a chance that it may rupture and oil may escape from the vault. Transformer rupture can result in public injury, property damage and/or environmental contamination.

- Non-financial Benefits:
  Non-financial benefits include increased public and worker safety, reduced risk of oil spills (environmental impact), and increased feeder reliability due to reduction in transformer failures.

- Summary of Financial Benefits (if applicable) and Costs:
  A leaking transformer without PTO installed would have to be replaced on emergency if it fails. The cost for an in-service transformer failure and replacement would cost approximately $130k.

- Technical Evaluation/Analysis:
  The PTO program, among other transformer failure mitigation programs, has contributed to a significant reduction to in-service transformer failures. The table below shows the number of in-service transformer failures from 2006 through 2017. The number of failures experienced in 2012-2017 (130) is approximately 60% lower than what was experienced in 2006-2011 (345).

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
In service Transformer Failures	120	70	52	34	42	27	27	14	21	22	16	30

- Project Relationships (if applicable):
  The Remote Monitoring System 3rd Generation Program is required to support the PTO program, as PTO sensors require 3rd generation transmitters to function properly.

- Basis for Estimate:
  The basis for the estimates used in this program is the historic unit cost for the installation of pressure, temperature, and oil level sensors. There are approximately 2,700 remaining to be installed.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	782	866	1,551	1,683		2,291
M&S	677	986	2,171	859		1,230
A/P	132	25	59	61		7
Other	-	38	-	-		-
Overheads	990	1,159	1,779	1,341		1,735
Total	**2,581**	**3,074**	**5,560**	**3,944**	**-**	**5,262**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,039	469	482	500	506
M&S	1,554	694	707	683	671
A/P	120	47	50	49	49
Other	610	277	275	261	269
Overheads	1,320	513	486	507	505
Total	**4,643**	**2,000**	**2,000**	**2,000**	**2,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Primary Feeder Reliability
Project Manager	Joe Lenge
Hyperion Project Number	PR.21490393, PR.5ED0081, PR.5ED2081, PR.5ED7081
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
The Network Reliability Index (NRI) is a measure used to ensure the reliability of all 65 networks on the Con Edison distribution system. The current goal is for all of the 65 networks to have an individual score for the NRI application of less than 1.0 per unit. Factors that directly impact network scores include component failure rates, load growth causing higher component loading, and longer and elevated predicted periods of heat stress. As these values are updated each year, the scores each network receives are subject to change and potentially could worsen. In order to maintain each network's score below the goal, it is necessary to perform reliability work in networks with a score above 0.9 or above 0.5 when a 2 degree weather adjustment increase is factored in. Reliability work that is done that will improve the index includes the removal of poorly performing components. Examples of poorly performing primary components include Paper Insulated Lead Covered (PILC) primary cable, PILC stop joints and vintage Cross Linked Polyethylene (XLPE) primary cable that was manufactured and installed between the years of 1970 and 1975, or the first generation of underground sectionalizing switches that were motor operated three phase SF6 (sulfur hexafluoride) gas insulated switches. Each year all primary components are reviewed based upon experienced failures and failure rates are updated and further poor performing components could be added.

In addition to removing poorly performing components, other reliability projects that will improve a network's score include the installation of underground sectionalizing switches, interrupting devices, or the establishment of new feeders within a network. The NRI program is used to determine best candidate feeders for underground sectionalizing switches or interrupting devices, however a review of the actual feeder is made to determine if placement is feasible. Substation Engineering is consulted to determine if spare cubicles are available in an area substation that would allow for the establishment of a new feeder. Once available cubicles are identified, only specific feeders can be candidates to be split or de-bifurcated to create a new feeder based upon that networks specific primary banding design and configuration.

Justification Summary:

PILC Cable Removal Program

The program began in the mid 1980's due to concerns over the reliability and potential environmental impact of Paper Insulated Lead Covered (PILC) cable. PILC cable contains a dielectric fluid (usually a mineral oil) and a lead sheath that are potential environmental contaminants. Failure data collected during the 1980's also showed that older PILC cable had a higher failure rate in summer months.

PILC cable and the associated transition splices (stop-joints connecting PILC cable to the newer solid dielectric cable) have elevated failure rates, especially during summer heat-waves. Transition splices have been responsible for cascading feeder failures where multiple outages have put the network at an increased risk of shutdown. The replacement of the PILC cable and associated transition splices reduces that risk.

1970's Vintage XLPE Cable Removal Program

The first vintage of Cross Linked Polyethylene (XLPE) insulated primary cables manufactured and installed between 1970 and 1975 have been recognized as having a high failure rate due to excessive treeing in the insulation material. Between the years 2013 to 2017, XLPE cables have failed at an average rate of 56 OA's and 27 FOT's (83 total) per year across the system. Mitigating this high failure component reduces system OA's, stress to the system, and manpower during times of high projected failure rates, such as heat storms.

There are approximately 5,900 sections (1,800,000 linear feet) of 1970-1975 vintage XLPE cable remaining in the system.

Underground Interrupter & Sectionalizing Switches Program

Sectionalizing switches reduce the amount of load shifted to other distribution feeders by allowing isolation of faulted segments of a feeder. The un-faulted portion of the feeder and associated transformers may then be re-energized. This in turn reduces the likelihood of failure of adjacent feeders that pick up the load of the faulted feeder.

The interrupter device prevents feeders from automatically opening out of service when a fault occurs downstream from the interrupter. The interrupter device operates instantaneously to isolate primary faults detected downstream from the device. The interrupter device is coordinated to operate before the corresponding Area Station feeder breaker thereby preventing the entire feeder from going out of service. Un-faulted sections remain in service. The faulted and isolated cable sections can be processed from the interrupter device to reduce restoration time.

Feeder restoration time plays an important role in network reliability and as more feeders are out of service, the higher the probability of a network going into a cascading event. Reliability models assume components will be unavailable for some time during which they are repaired. Since this program replaces the first generation manually operated sectionalizing switches with remote control units, the restoration time for a faulted feeder is reduced since the un-faulted portion of the feeder can be returned to service.
The first generation of underground sectionalizing switches that were deployed on the distribution system were motor operated three phase SF6 (sulfur hexafluoride) gas insulated switches. Over time these switches have become problematic to operate due to motor failure, or loss of SF6 gas. These switches are being selectively targeted for replacement with the newest variant, which is a vacuum based switch.

New Feeders

This program improves reliability by establishing new distribution feeders. This is achieved by either splitting or "de-bifurcating" existing feeders (supplying from individual breakers, two feeders formerly supplied from a single breaker) to create two separate feeders. The program utilizes existing spare feeder positions in area substations, or constructs new area substation cubicles where necessary, to accommodate the new distribution feeders.

<u>Supplemental Information</u>:

- <u>Alternatives</u>:
  An alternative to the PILC Cable Replacement program would be to replace only the high failure rate transition splices with a newer, more reliable splice design. This would reduce the cost of the program by one-third, but would not have the same impact on reliability as removing both the cable and the transition splice. The PILC cable is the oldest cable on our system with a failure rate two and one half times that of newer Ethylene Propylene Rubber (EPR) cable. Replacing the nearly 7,000 in-service transition splices would take nearly the same amount of time as replacing the PILC cable sections however will result in a less reliable system.

  Another alternative to the PILC cable replacement program would be a cable diagnostic system that could accurately determine the "health" of our PILC cable system. We could then target only un-healthy cable for replacement. Although there are several systems available, including: Partial Discharge and Tan-Delta, none have proven to be effective on our primary distribution system.

  An increased use of the Hipot testing (both DC and VLF) could be used to ferret out defective cable that could fail while in service. While Hipot testing has increased the amount of PILC cable and stop-joint removals, the frequent use of this cable diagnostic has increased the number of in-service failures since it is a destructive test.

- <u>Risk of No Action</u>:
  Reliability projects are required to maintain all of the 65 networks below the goal of 1.0. The NRI of the networks changes from year to year as failure rates and loading on the components change. These changes often lead to an increasing NRI for specific networks. In order to maintain the reliability of the entire network distribution systems, CECONY has established a goal to have each of its 65 networks below of 1.0 per unit. This goal has been established in order to reduce the potential risk of a network shutdown. Work in this program lowers the NRI index for each network. Without these projects the index would grow above the corporate goal and translate into a higher risk of a network shut down occurring.

- <u>Non-financial Benefits</u>:
  The PILC Cable Removal Program has an environmental benefit of removing potentially hazardous material, like lead and oil, from the environment.

  The Underground (UG) Sectionalizing Switch Program reduces the potential to leak SF6 gas (a greenhouse gas) into the environment as the new Elastimold underground switches contain no SF6 gas.
- <u>Summary of Financial Benefits (if applicable) and Costs</u>:
  The reliability performance mechanism in the current rate agreement provides for up to $10 million in fines for a single major outage to a network. By increasing NRI above the 1.0 pu threshold, the reliability projects detailed reduce the risk of a significant network event and the associated penalties.

  The new remotely operated sectionalizing switches reduce the maintenance costs associated with the mandatory operation of the existing switches once every six months. The SCADA equipment installed on the new vacuum switches has remote diagnostics capability and only requires a field visit for repairs if it fails. There is no recurring communication expense associated with the remote operation of the switches.

- Technical Evaluation/Analysis:
  The summer network PILC cable failure rate is, on average, three and one-half times greater than the newer extruded EPR cable (0.156 vs. 0.045). The network summer failure rate for Transition splices (stop-Joints), connecting PILC cable to extruded type cables , is, on average, nine and one-half times greater than extruded cable splices (0.471 vs. 0.049).

  Transition splices continue to be the largest contributor to primary feeder failures during the summer period. Raychem 3W-1W Stop-Joints, which comprise only five percent of the network splice population, account for 45 percent of the primary network splice failures. The only practical method to remove these heat sensitive transition splices is through the removal of the attached PILC cable. The primary network system is currently comprised of approximately nine percent PILC cable while the associated transition splices make up around five percent of the splice population.

- Project Relationships (if applicable):
  None

- Basis for Estimate:
  The basis for the estimated costs in the program are the historical unit costs for installation of PILC cable sections, stop-joints, underground switches and new feeder positions.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	6,558	1,241	1,894	3,225		1,116
M&S	7,988	1,025	1,596	2,530		2,120
A/P	2,549	1,319	664	2,022		608
Other	(89)	16	-	41		69
Overheads	10,942	2,908	2,228	3,385		1,462
Total	**27,948**	**6,509**	**6,382**	**11,203**		**5,375**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	750	1,833	2,630	3,363	2,875
M&S	1,832	1,993	2,860	3,657	3,126
A/P	285	936	1,342	1,717	1,467
Other	3	5	7	9	8
Overheads	1,016	2,733	3,922	5,015	4,285
Total	**4,887**	**7,500**	**10,761**	**13,761**	**11,761**

X	Capital
	O&M

2019 – Central Operations / Substation Operations.

Project/Program Title	Pumping Plant Improvement Program.
Project Manager	Dan Brown
Hyperion Project Number	PR.8ES4200
Status of Project	In-Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

This program consists of improvements to the pumping and cooling plants that support the company's 69kV, 138kV, and 345kV underground transmission systems. These improvements are upgrades to modernize existing equipment, or they are complete plant replacements if necessary. Focus is given to projects that reduce environmental risk associated with dielectric fluid release into the environment.

A Pumping Plant is a facility that pressurizes and fills underground transmission lines with dielectric fluid. This fluid is required for the operation of the electric cables. A Cooling Plant is a facility that extracts fluid from an underground transmission cable and then cools this fluid before pumping it back into the underground line. A cooling plant allows existing transmission lines to carry more power. A Public Utility Regulating Stations (PURS) Plant is a particular type of cooling plant that is installed exclusively on the 345kV system.

The scope of work can be summarized as follows:

- Control Panel Upgrades: The Company decided in 2010 to change direction regarding the nature of this program. We took into consideration that since the inception of this program, the highest priority skid replacements have already been replaced. A skid replacement consists of replacing control panels and upgrading hydraulic components. We further evaluated those plants remaining (now approximately 55) to be refurbished and made a determination that for the most part, the pumps and ladders are in generally good condition, but the control panels are in poor condition. Furthermore, a root cause analysis determined that the control panels, which have electrical and dielectric/mechanical components residing in a common control cubicle, increase the likelihood of catastrophic fire. A cost benefit analysis was performed and has shown that with this new approach, we can effectively replace two control panels for approximately the same cost as one skid replacement, thereby addressing twice as many of the more serious pump plant issues. Control Panel Upgrades consist of the removal of the existing control panel, segregation of the dielectric and electric components, installation of pipe mounted transducers, a PLC with HMI and cyber-secure 1- way communication to ECC and replacement of leaking ladder and header valves as needed. There are still approximately three plants unsuitable for a control panel replacement, and our plan is to address one skid replacement per year beginning in 2016. Our current target for control panel replacements is six per year or four Control Panels and one skid replacement.

- Partial ("Skid Replacements") and complete pumping plants replacements: This consists of full control panel replacements plus replacement and upgrades to all hydraulic components (Pumps and Ladders) in order to improve the operability of the facilities. In a skid replacement, some of the existing components of the original pumphouse are left in place, most notably the storage tank and the existing structure house. In a complete replacement, none of the original components are left in place, everything is replaced. Since skid replacements are typically a lower cost alternative than a full replacement, we look to use this scope where possible versus a full replacement.

- PURS Plant upgrades: This consists of the installation of variable frequency motor drives (VFD's) for energy efficiency and reliability; replacement of existing analog controls systems with new digital systems; replacement and upgrades to hydraulic components; installation of new communications systems.

- Cooling Plant upgrades: This consists of replacement of existing analog controls systems with new digital systems and replacement/upgrades to hydraulic and cooling components. It also may include replacement of the heat exchangers, cooling towers and oil and water pumps as needed based on current condition, maintenance history, and vintage.

- Cooling Plant Heat Exchanger replacements: Each cooling plant and each PURS plant has a series of heat exchangers. This work consists of the replacement of heat exchangers as conditions warrant.

- Pressurization Plant Communication System: These projects involve replacing existing telephone line dial-up communication systems between Pressurization Plants and the Shift Managers at the Energy Control Center (ECC) with a new fiber optic, cyber-secure communication system. This new system will provide real-time Pressurization Plant alarms, including existing Leak Warning Alarms, and plant data to the ECC. The scope of this program is to replace the communication systems in plants that were upgraded in the 1990s and 2000s. The communication system and Leak Warning alarms for the current control panel upgrade projects will be addressed in the Environmental Enhancements Program.

  Upgrading the communication system includes the installation of fiber optic cables, conduits, associated accessories (e.g. patch panels, connectors, pigtails, etc.), media converters, and switches, to connect new generation Programmable Logic Controllers (PLCs) installed at Pressurization Plants in various Substations to the ECC Supervisory Control and Data Acquisition (SCADA) system. To do this, either a new Remote Terminal Unit (RTU) will be installed or an existing RTU with spare data input points will be utilized. Without detailed engineering for these projects at this time, it is assumed that stations with one pressurization plant will be connected to an existing station RTU. This will be evaluated for each substation. A communication link will be established between the RTU at the substation and the SCADA system at the ECC. For the Shift Managers to collect and analyze the plant data, dedicated servers with customized software programs will be installed at both the ECC and Alternate ECC (AECC).

Justification Summary:

The operation and optimization of pumping plant and cooling plant facilities is essential to the reliability of the transmission system. The ability to cool a major feeder is a necessity when it comes to the distribution of power – thus the pumping plant improvement program is vital to ensuring efficient and reliable transmission of power to our customers. These installations and upgrades will provide the ability to respond to alarms expeditiously, allowing personnel to mitigate irregular system conditions, prevent the removal of major equipment from service and reduce the risk of fires, which can completely shut down pumping plants and possibly neighboring facilities. Additionally, PURS are being equipped with variable frequency motor drives, which regulate the pressurization and circulation of oil in a feeder and reduce stress on the feeder cables.

The justification for each project category is as follows:

- Control Panel Upgrades: As stated in the work description, a cost/benefit analysis was performed and has shown that we can effectively replace two control panels for approximately the same cost as one skid replacement and address twice as many of the more serious pump plant issues.

- Partial refurbishment ("Skid Replacements") or complete pumping plants replacements: Most of these plants are in service for over 30 years. These plants operate by monitoring the status of dielectric fluid that has been transported via small tubing to a centralized control unit. This extensive tubing is prone to failure and leaking, while these centralized control units, which employ analog gauges, mechanical switches, and electro-mechanical relays to process information, are not extremely reliable. Implementation of this program will ensure that correct pressures, tank levels, and alarms are displayed and transmitted, as well as eliminating environmental oil leaks. The installation of new digital PLC-driven controls systems will allow system operators to gather a greater level of information in assessing system conditions and leaks.

- PURS Plant upgrades: There are thirty nine (39) existing PURS Plants on 345 kV Feeders M51, M52, 71 and 72, 61, 62, 63, 45, 46, M54 and M55. None of the above PURS Plants have pump speed control capability, resulting in unnecessary power consumption during light feeder loads and during cooler ambient temperature. Many of the existing hydraulic and electronic components are unreliable and are not supported by vendors. Equipment malfunctions result in PURS plant shutoffs, which in turn result in the de-rating of feeders. The installation of new digital PLC-driven controls systems will allow system operators to gather a greater level of information in assessing system conditions to optimize plant performance.

- Cooling Plant upgrades: This consists of replacement of existing analog controls systems with new digital systems; and replacement and upgrades to hydraulic and cooling components. There are 36 circulating plants on 345 kV and 138 kV transmission feeders, most of which are over 30 years old. The older plants have oil leaks, antiquated controls, chart recorders and alarm panels no longer supported by the equipment manufacturer, making it difficult to obtain replacement parts. The installation of new digital PLC-driven controls systems will allow system operators to gather a greater level of information in assessing system conditions and leaks.

- Cooling plant heat exchanger replacements: Heat exchangers carry dielectric fluid across internal radiators for cooling. Aging heat exchangers can fail or clog, resulting in loss of cooling ability or even dielectric fluid leaks. These particular pieces of equipment are occasionally identified as having the potential for this type of failure. Replacement of these units, on an as-needed basis, will result in improved cooling ability and reduction in potential of fluid loss to the environment.

- Pressurization Plant Communication System: Feeders with slow or static dielectric fluid circulation have basic, fixed-point leak detection alarms typically consisting of frequent pump operation alarms and pressure transducers that monitor loss of pressure. Existing leak alarms are communicated back to the ECC via dial-up telephone line modems. This communication link is slow and the lines are prone to issues requiring third-party telephone company support, which can delay alarm response. Other alarms are bundled into a general category alarm, which requires operator investigation prior to initiating appropriate action. Consequently, dielectric fluid leaks on these feeders utilizing this basic system may take longer to identify. To improve the reliability of the communication system will help reduce dielectric fluid loss into the environment. Communication over fiber optic cables instead of copper telephone lines is also more resilient to adverse weather conditions such as flooding. These projects will upgrade the communication system associated with 45 Pressurization Plants located in various substations. Each year we will target the installation of 4 new RTUs and the connection of 15 plants to either the new RTU or an existing RTU.

Supplemental Information:

- Alternatives: There are no feasible alternatives but, as noted above, Substation Operations will implement the most cost effective feasible project dependent upon the circumstances.

- Risk of No Action: No action would result in equipment failure, causing damage to equipment and/or personnel, and continued degradation of equipment, resulting in oil leaks to the environment. As noted above, this program mitigates a number of environmental and operational concerns that we have in the pump houses, PURS, and cooling plants. For example, the importance of removing the capillary tubing from the pump house control cabinets was re-emphasized following the pump house #2 fire at Dunwoodie.

- Non-financial Benefits: These initiatives would improve the ability to detect and stop leaks, which decreases the potential for oil leaks into the environment.

- Summary of Financial Benefits (if applicable) and Costs: These improvements avoid maintenance costs, increase reliability, and lower failure rates associated with microprocessor controlled pressure control system. In addition, these improvements help avoid costs from fines for regulatory noncompliance.

- Technical Evaluation/Analysis: The nature and vintage of these units warrants either full or partial replacement. These units all warrant a control panel replacement that segregates oil-containing components from electrical components and greatly reduces the risk of fire. Our direction to primarily focus on partial replacement has been based on a cost analysis that determined we can essentially replace two control panels for the cost of one full replacement, thereby more effectively mitigating more risk of catastrophic event.

- Project Relationships (if applicable): Plants located in stations targeted by the storm hardening efforts will be upgraded under that program. All other upgrades under this program will take into account any storm hardening mitigation that may be needed to meet current standards.

- Basis for Estimate: Based on the cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,352	1,372	1,311	1,360		1,025
M&S	575	741	629	929		760
A/P	849	215	227	225		135
Other	35	14	16	53		95
Overheads	1,850	1,791	1,230	1,334		933
Total	**4,661**	**4,132**	**3,413**	**3,901**	**-**	**2,949**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,080	1,912	1,365	1,365	1,365
M&S	600	983	702	702	702
A/P	255	464	351	351	351
Other	59	133	94	111	96
Overheads	1,006	1,970	1,388	1,371	1,386
Total	**3,000**	**5,462**	**3,900**	**3,900**	**3,900**

X	Capital
	O&M

2019 – Central Operations/Substation Operations.

Project/Program Title	Ramapo - Install New Surge Arrestors
Project Manager	Mike Lentini
Hyperion Project Number	PR.20987102
Status of Project	Engineering/Planning
Estimated Start Date	2016
Estimated Completion Date	2020
Work Plan Category	Strategic.

Work Description:
This project will provide the following upgrades:

a) Replace existing air gap surge arresters with new metal oxide surge arresters at the location where all six incoming 345kV feeders terminate to the substation
b) Install three new lightning masts in the phase angle regulator (PAR) area
c) Install new surge arresters at six new locations of the existing 345kV bus

This upgrade will mitigate the deficiency in the reliability of existing air gap surge arresters, close the gap in the existing shield wire design, and will eliminate the possibility of damage to substation equipment due to lightning surge via a feeder while feeder breakers are open and disconnect switches are closed.

Justification Summary:
Currently, air gap surge protectors protect the substation from any incoming high voltage surge from external sources via overhead 500kV and 345 kV feeders, except the lines connected to the adjacent Orange & Rockland (O&R) 138kV substation. As physical characteristics of air vary with different atmospheric conditions, the performance of air gap surge arresters is inconsistent. Therefore, the degree of protection existing air gap surge arresters provide varies with weather conditions. To address the performance inconsistencies new metal oxide varistor (MOV) type surge arresters will be installed. They are constructed of semiconductor disks enclosed in porcelain housing. They perform consistently in all atmospheric conditions, and allow the station to maintain sufficient protective margins for various lightning and switching surges that may be impinged on the system.

Supplemental Information:

- Alternatives: There is currently one option to address the deficiencies in the existing surge protection system at the Ramapo 345kV station. The option is outlined below:

  Option:
  - Replace existing air gap surge arresters with new metal oxide surge arresters at locations where existing air gap surge protectors are located
  - Install three new lightning masts in the PAR area

  This option is not recommended. Although it is a low probability scenario, this partially upgraded surge protection system provides low degree of protection to the substation equipment from lightning impinging on the substation via feeders while associated breakers are open. Therefore, the possibility of inflicting severe damage to the substation by a lightning strike would persist.

- Risk of No Action: Based on IEEE standards 998-2012 and 1313.2-1999, the current installation does not protect Ramapo 345kV substation adequately from voltage surge caused by switching surges and lightning surges. Therefore, without the proposed upgrade, the substation will remain exposed to the possibility of damage.

- Non-financial Benefits: This program provides risk mitigation and supports the Company's mission to provide safe, reliable energy to our customers.

- Summary of Financial Benefits (if applicable) and Costs: A significant incident will substantially impact the Company. As noted previously, the project will greatly reduce the possibility of the damage to substation equipment from lightning surges.

- Technical Evaluation/Analysis: An analysis of existing overhead shield wire systems at the Ramapo 345kV station was performed based on IEEE Standards 998-2012. From that analysis, Con Edison determined that the existing overhead shield wires do not provide adequate coverage from direct lightning strike to the area of PAR Nos. 3500 and 4500. The substation is exposed to possible direct lightning strike due to this lack of protection.

  Additionally, from recent electromagnetic transient analysis on the basis of IEEE Standard 1313.2-1999, surge arresters are required at six of the new 345kV bus locations inside the substation to protect equipment against potential damages due to lightning surges.

- Project Relationships (if applicable): N/A

- Basis for Estimate: The funding request is based upon an Engineering Appropriation Estimate performed for this work.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	43	241		111
M&S	-	-	211	2		57
A/P	-	-	4	692		6
Other	-	-	14	3		5
Overheads	-	-	96	452		174
Total	**-**	**-**	**368**	**1,390**	**-**	**353**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	435	435	-	-	-
M&S	101	87	-	-	-
A/P	363	350	-	-	-
Other	97	80	-	-	-
Overheads	454	498	-	-	-
Total	**1,450**	**1,450**	**-**	**-**	**-**

X	Capital
	O&M

2019 – Central Operations / Substation Operations.

Project/Program Title	Reinforced Ground Grid Program.
Project Manager	Steven Bryan
Hyperion Project Number	PR.1ES7400
Status of Project	In-Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:

The intent of this program is to ensure the effectiveness of the grounding system at each substation. As a result of a 2005 lightning incident at Astoria East Substation, a program has been implemented, as specified in Con Edison procedure CE-ES-1001, to test the ground mats of all substations periodically. This program reinforces the ground grid of those stations with degraded grounding systems that are identified by this periodic testing. Typical work consists of trenching the new grounding patterns throughout the area to reinforce the existing grounding grid. The trenching is filled in by new grounding conductors and cadwelds that are required to connect these conductors. Once connected and tested the trenches need to be backfilled and the grounding (pigtails) connected to the proper equipment. Also we are required to remove mechanical connections that are found connected in the ground while performing the work for reinforcement, since they are weak points for corrosion. These new conductors are connected to the existing ground grid and connected to the high resistance equipment. Typically (2) substation ground grids will be reinforced each year. The next two stations on the priority list are significantly bigger in scope and the intent is to address one per year in 2019 (Dunwoodie Substation) and 2020 (E179th St. Substation Upper Yard).

Current substation projects include:

2019 – 2023 Projects:

- Dunwoodie Substation - 2019
- E179th St. Substation Upper Yard - 2020
- Farragut Substation - 2021
- Jamaica Substation - 2022
- Glendale Substation – 2022
- Gowanus Substation -2023

Justification Summary:

In August 2005, lightning struck a transmission tower at the Astoria East Substation and caused extensive damage to a current transformer revenue metering and its associated wiring. An investigation revealed that the A-frame Tower was not properly grounded and various substation structures and equipment within the Astoria East yard had high grounding impedance. Inspections to determine the cause of the high impedance revealed several instances of damaged ground connection cables and one of the two main 1000 MCM (million cubic meters) cables that made up the existing main ground grid were badly corroded.

The excessive corrosion and deterioration of ground cables and underground connectors due to age related degradation require the ground grid be reinforced to minimize damage, in the event of lightning strikes, switching surges, and equipment and/or feeder faults. Ground grid deficiencies are identified through the Company's periodic ground impedance test program. Ground grid continuity measurements were taken at Stations that were built at the same time as the Astoria East Substation.

This program is driven by specifications CE-ES-2002-10 (Design Criteria) and CE-ES-1001 (Testing). Key criteria driving action are ground grid impedance and ground grid continuity. The stations targeted do not meet acceptable levels in one or both of these categories. The work covered under the program represents the requirements to bring the station ground grid back to spec.

Supplemental Information:

- Alternatives: One option is to install new ground grids. This would require extensive outages while the new ground grids are being installed. The extent and location of corrosion are unknown and would require extensive excavation, isolation, and testing to determine the repair requirements. This option is not recommended as testing and repair costs are far greater than the cost of reinforcement. Reinforcement of the ground grids does not require system outages.

- Risk of No Action: Taking no action is not recommended as existing ground grids can pose a potential public safety issue with ungrounded fences and high resistance connections within the existing station grids. Both conditions can result in high ground potential rises during fault conditions that could endanger personnel and cause equipment damage.

- Non-financial Benefits: The reinforcement of the ground grid minimizes damage in the event of lightning strikes, switching surges, equipment, and/or feeder faults.

- Summary of Financial Benefits (if applicable) and Costs: The reinforcement of the ground grid helps avoid costly repairs to damaged equipment and protect the safety of personnel in the event of a fault. This helps to minimize the costs associated with an incident.

- Technical Evaluation/Analysis: Most of the ground grid reinforcement candidates have been in service since the 1960s. Standards at the time did not require fence grounding and mechanical connectors to be installed. High resistance grid connections exist because of the corrosion of ground cables and the deterioration of the mechanical connectors. By reinforcing the grounding system, including the fencing grounds, the performance of the ground grids will be substantially improved.

- Project Relationships (if applicable): **NA**

- Basis for Estimate: Near term work based on Engineering estimates, which are based on similar types of work done in the past. Outer term work based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature. The average unit cost has been approximately $800k and the budget usually includes two per year. The next two stations are significantly larger in size and will require a higher unit cost, $2M-$3M range per year.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	139	570	(47)	436		268
M&S	9	52	-	175		88
A/P	10	543	(1)	280		377
Other	-	57	-	10		4
Overheads	149	833	(41)	413		283
Total	**307**	**2,055**	**(89)**	**1,314**	**-**	**1,020**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	580	870	467	1,426	357
M&S	160	240	113	339	80
A/P	560	780	435	1,328	332
Other	81	90	55	197	49
Overheads	619	1,020	540	1,627	412
Total	**2,000**	**3,000**	**1,609**	**4,917**	**1,230**

X	Capital
	O&M

2019 – Central Operations/ Substation Operations

Project/Program Title	Relay Modifications Program.
Project Manager	James Neilis
Hyperion Project Number	PR.2ES7800
Status of Project	In-Progress
Estimated Start Date	2007
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
This program provides for technology upgrades to the relay protection systems at various substations. The projects listed below are part of the Relay Modifications Program:

- Replace obsolete electro-mechanical and solid state transmission feeder differential relays which are prone to mis-operate during communication line disturbances. These relays include types HCB and LCB II Relays (Replace 1st and 2nd Line Relay Protection): New microprocessor relays are being installed to replace HCB pilot wire protection communication circuits that do not provide protection against communication line disturbance. Replace the first and second line HCB/LCB II- pilot wire relay with an SEL 411L line differential relay. Replace existing breaker failure relays with ALSTOM P141. Install first and second line breaker failure self-reset lockout relays and transfer trip receive self-reset lockout relays. Replacement of the relay system includes, but is not limited to the following feeders: 24051, 29231, 29232, 99032, W73/W89, 15032, 31231, 15054/34052, 21, 31232, 61, 36311, 62, 63, W75, based where the maximum fault current exceeds their rating.

- Replace MCO Relays: Type MCO is a solid-state overcurrent relay manufactured by ABB and has been applied as a ground differential relay for Area station transformers. The relay is obsolete and is prone to mis-operate due to certain transients and as a result, the relays have been removed from service system wide. These MCO relays are being replaced with a Basler BE1-851 microprocessor relay, which was tested and found to be not affected by transients. The auxiliary current transformers, which provide the design input to the MCO relays, are being replaced with C400 CT's.

- Replace obsolete electro-mechanical and solid state distance relays which are prone to mis-operate for external faults and also do not have any spares available from manufacturers. New microprocessor relays will be installed to replace GCX/GCXG/SLY/KD relays. Replace the first line relay with SEL 421 directional comparison unblocking scheme and the second line relay with SEL 411L current differential relay. Replacement of the relay system includes, but is not limited to the following feeders: Y94,69, F30/W80, W79/W93

Justification Summary:
Con Edison's relay protection systems employs over 60,000 relays. Approximately 90% of these are electromechanical relays, with a smaller number of solid-state relays. Over the past decade, Con Edison has either replaced some of the electromechanical and solid-state relays with microprocessor relays, or

has added new microprocessor relays whenever new equipment and/or substations have been added to the system.

In general, the electromechanical relays are quite robust in design. However, spare parts and/or new replacement relays are difficult to obtain as the original suppliers stopped manufacturing them over two decades ago. Early-generation solid-state relays have proven not to be robust and the manufacturers often have discontinued support and supply of spare parts. In addition, both electromechanical and solid-state relays do not possess the ability to electronically store event information and transmit the data to a remote location. This event information is valuable to analyze the system events and decide corrective action to improve system reliability. Implementation of this program will upgrade protection equipment to modern standards, improve reliability, prevent incorrect automatic relay operations, and provide better post event analysis capabilities and sequence of events recordings.

Supplemental Information:

- Alternatives: The alternatives considered are shown for each project below:

  Replace HCB Relays (Replace 1st and 2nd Line Relay Protection): No alternative

  - Replace LCB Relays: No Alternatives
  - Replace MCO Relays: No alternatives.
  - Replace electromechanical and solid state distance relays: No alternatives

- Risk of No Action: The concerns associated with no action for each project are listed below:

  - Replace HCB and LCB Relays (Replace 1st and 2nd Line Relay Protection): Continued use of the existing HCB and directional ground relays with the existing direct current transfer trip (DCTT) system may cause inadvertent loss of the feeders due to mis-operations; continued use of the existing LCB relays increases the risk of inadvertent loss of feeders due to mis-operation of the relays.
  - Replace MCO Relays: No action may risk the loss of a substation.
  - Replace Electromechanical and solid state distance relays
    With the continued use of the existing protection system, there is risk of inadvertent loss of feeders due to relay mis-operations affecting the transmission reliability.

- Non-financial Benefits: This program increases overall system reliability, as it is aimed at reducing the likelihood of relay system mis-operations. In cases where protective relay systems should have caused a trip out, but did not, equipment may be damaged and require long term repairs or replacements. In cases where a protective relay system inadvertently trips out equipment, load trips may occur if this occurs during another system disturbance or when a station is already in an N-1 or N-2 condition.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis:

  - Replace HCB and LCB Relays (Replace 1st and 2nd Line Relay Protection): Replace 1st and 2nd Line HCB Relay Protection systems that can no longer be maintained to meet the Original Equipment Manufacturer (OEM) specifications. The newly installed relays will have self-diagnostics and event recording capabilities which contribute to increased system reliability.

    The existing 1st and 2nd Line LCB Relay Protection System is provided by solid-state relays. Replace solid-state relays with microprocessor type relays with inherent design features that can override communication line disturbances. The new relays will also have built-in oscillography and sequence of events recording capabilities, which will contribute to increased system reliability.

- Project Relationships (if applicable): N/A

- Basis for Estimate: Near term work is based on Engineering estimates, which are based on similar types of work done in the past. Outer term work is based on the costs of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature.
  The average unit cost for one station is $1 million, two stations are $2 million and three stations are $3.7 million. There are different mixes of projects per year.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	3,088	2,316	2,119	5,646		6,023
M&S	1,249	729	1,361	2,486		2,865
A/P	246	343	119	174		145
Other	169	62	43	239		376
Overheads	3,872	2891	2,047	5,100		4,744
Total	**8,624**	**6,340**	**5,688**	**13,644**		**14,154**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	3,798	4,840	4,840	4,840	4,840
M&S	1,709	1,839	1,897	1,936	1,906
A/P	475	605	605	605	605
Other	191	241	242	256	243
Overheads	3,322	4,575	4,516	4,463	4,506
Total	**9,495**	**12,100**	**12,100**	**12,100**	**12,100**

X	Capital
	O&M

2019 – Central Operations / Substation Operations.

Project/Program Title	Relay Protection Communications Upgrade
Project Manager	JIM NEILIS
Hyperion Project Number	PR.21562316
Status of Project	Engineering/Planning
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

The intent of this program is to remove from service inadequate communications infrastructure used, in part or in whole, for relay protection and replace it with modern, actively supported, and reliable communications infrastructure. For most locations, this program will also provide two independent communication systems for relay protection, which will increase the reliability of the electric system by eliminating single point mode of failure in the relay protection communication networks. This second objective is in line with Con Edison's relay protection design philosophy. The work is to take place at various locations throughout the system. The work shall be divided into three categories;

1) The upgrade of Corporate Communication Telephone Network (CCTN upgrades)
2) The upgrade of Verizon communications infrastructure (Verizon upgrades)
3) The upgrade of relay protection equipment (relay comm. upgrades)

A CCTN upgrade will include the extension of the CCTN network to a facility that currently does not have it. Work will include extending fiber optic cable from the nearest feasible source to the substation that requires it. In addition, a CCTN node will be installed consisting of the appropriate equipment to allow for service to be available at the station. The installed equipment will be the property of Con Edison. We forecast the cost of such an upgrade to be approximately $1.9 million. There is an estimated 12 upgrades required system wide.

A Verizon upgrade will include the installation of a Verizon fiber optic node in our stations that currently only have Verizon copper service or where the fiber service is insufficient to meet relay protection needs. The installation of the Verizon node will be carried out by Verizon, with Con Edison supporting the installation by providing cabinet, conduit, and cable installations as necessary. Some additional equipment may be required to interface with relay protection for adequate protection system operation. All the Verizon equipment installed by Verizon and paid for by Con Edison will remain the property of Verizon while all the support equipment installed by Con Edison will be Con Edison property. We forecast the cost of such an upgrade to be $0.3 million. There is an estimated 8 upgrades required system wide.

A relay comm. upgrade will include the upgrade, modification, addition, or replacement of those relay elements necessary for, or directly related to, the communications of the relay protection system, such that the existing protection system can utilize the upgraded communications infrastructure properly. This is not intended to be a complete relay system replacement, but rather, only a partial or minor replacement of the relay systems' communication elements. The installed equipment will be the property of Con Edison. We forecast the cost of such an upgrade will be in the area of $0.5 million and there are numerous projects falling under this category.

To achieve substantial conversion of communications systems over the next five years, we plan to include each year at least two CCTN upgrades and two to three Verizon and relay comm. upgrades. We forecast the total cost per year to be $2.5M in 2017, $4M in 2018, $7M in 2018, $5M and $5.5M for 2020 and 2021 respectively.

Justification Summary:

The underlying reasons for proposing the aforementioned upgrades are multifaceted, with each aspect adding to the overall goal of increasing system reliability. Of primary concern is the migration of relay protection systems off failed, failing, or problematic communication links. At several locations and for several elements, the relay protection systems have been out of service for time periods ranging from hours to months due to failed communication links. In the past five years, there have been over 50 occurrences of loss of protection on a high tension transmission feeder due to a copper communication line being out of service, with some resulting in equipment outages. Since the repair of these circuits is not under the authority of Con Edison, it is difficult to control the timeframe in which the equipment is returned to service.

Of secondary concern is the mitigation of single mode point of failure situations that may exist in the communication networks that serve independent relay protection systems protecting the same power system elements. The design philosophy with regard to relay protection communications given in Con Edison's EOM-CE-0111, which is based on NPCC Directory #4, dictates that communication systems of two independent relay protection systems protecting a single power system element shall also be independent. The reason for this is to prevent a single mode point of failure in the relay protection system in which the loss of a single element of the protection system (which includes its communication elements) would cause both independent relay protection systems protecting a single power system element to be defeated simultaneously. If both relay protection systems protecting a single element were to rely on a single fiber network only, be it Verizon or CCTN, and that network were to be compromised, then with a single failure, the power system element would be unprotected. Furthermore, if there is only one communication system servicing a station, and that communication system was to be compromised, then the entire station could lose protection for multiple elements simultaneously. Such a situation must be avoided as it has the potential to leave a large, contiguous portion of the system at risk of outage if a failure were to occur. Two independent communication networks are necessary to mitigate this, which Con Edison proposes to implement using CCTN and Verizon fiber services.

Supplemental Information:

- Alternatives:
    - Rely on Verizon to upgrade its infrastructure to Con Edison stations. This option is undesirable because of the lack of control over the schedule of the upgrades. Verizon may elect to upgrade service immediately or defer it until complete failure occurs. Furthermore, even when Verizon upgrades its service, Con Edison may have to do additional work to interface old relay systems with the new communications infrastructure. Finally, this option does not address the proposed CCTN upgrades, nor does it resolve single mode point of failure concerns.
    - Find other means of providing two completely independent relay protection systems. This option is undesirable because it involves a large investment of engineering time to develop a new philosophy that may be unproven or untested. Several existing technologies that satisfy this, such as the use of automatic ground switches, are currently being phased out because of their inadequacy. This also does not address immediate problems and concerns.

- Risk of No Action: Taking no action leaves the system in a state of increased vulnerability to communication system failures, which may cause equipment to be taken out of service or to be operated with limited protection. In addition, taking no action would fail to address current existing communication problems.

- Non-financial Benefits: Non-financial benefits include increasing system reliability by decreasing protection system outages caused by communication failures. The expansion of CCTN would also provide, as a secondary benefit, better corporate LAN network access to stations that currently rely on third party providers for network access, increasing Con Edison's control over LAN functionality at those stations. This expansion would also strengthen Con Edison's physical security and cyber security objectives by providing controlled and secured paths for security-critical data transfers at locations that currently do not have them. Finally, the upgrade will provide increased redundancy for SCADA and other control related communications to some stations by providing independent and redundant communications systems (current service provide by AT&T and Verizon may use the same equipment in the station to provide access).

- Summary of Financial Benefits (if applicable) and Costs: NA

- Technical Evaluation/Analysis: A survey was conducted to observe the number of communication failures over the past five years. There were over 50 occurrences of communication line failures that resulted in protection systems being out of service, with several of them resulting in equipment being taken out of service. There were several repeated failures as well. Most failures occurred on systems that used copper-based communication lines.

- Project Relationships (if applicable): This proposed program shares relationships with the Relay Modifications program and the Area Reliability program. Both of those programs have been used to provide a limited number of relay communication infrastructure upgrades in the past but have not been able to address many of the remaining problems.

- Basis for Estimate: The estimate is based on taking past actual project costs of similar projects and past OOM estimates for related project types and projecting these costs to future project requirements. The cost per location is approximately $1.9 million, with 1 location being completed in 2017, 2 in 2018, 3 in 2019 and 2020 and 2 in 2021, 2022 and 2023 under planning.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	312		272
M&S	-	-	-	230		14
A/P	-	-	-	1,118		455
Other	-	-	-	17		11
Overheads	-	-	-	564		292
Total	**-**	**-**	**-**	**2,241**		**1,044**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	3	1,350	1,575	1,365	1,365
M&S	150	270	315	270	270
A/P	60	105	140	111	102
Other	42	89	103	91	90
Overheads	558	1,186	1,367	1,163	1,174
Total	**1,500**	**3,000**	**3,500**	**3,000**	**3,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Remote Monitoring System 3rd Generation
Project Manager	Various
Hyperion Project Number	PR.5ED0141, PR.5ED4151, PR.2ED1141, PR.2ED3251, PR.2ED7831, PR.23440191
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Regulatory Required

Work Description:
This program provides funding for the replacement of defective units and installation of new Remote Monitoring System (RMS) 3rd generation (generation) transmitters at various network transformer vault locations throughout all regions. This includes all new transformer installations, transmitter replacements, and Remote Monitoring System Pressure, Temperature, and Oil level sensor (RMSPTO) field conversions. An average of 1,950 units will be installed per year by Company regional I&A (Installation and Apparatus) equipment personnel. As units fail in service new transmitters need to be installed.

Justification Summary:
This ongoing work is required to comply with the Reliability Performance Mechanism (RPM) associated with the Remote Monitoring System mandated by the New York State Public Service Commission. The RPM requires 90% of all transformers within a network to report real time equipment information once a month. Failure to comply with the Remote Monitoring System RPM metric will result in a revenue adjustment of $10 million per violation and up to a cap of $50 million annually.

In addition, the 3rd generation transmitter has a power flow direction feature which indicates the occurrence of a reverse power flow (Alive on Backfeed or ABF) condition. ABF occurs when one or more network protector(s) fails to open during a feeder outage. When these network protectors stay closed, they allow power to flow backwards from the secondary grid into the primary feeder due to a potential voltage difference. The 3rd generation transmitters' capability to indicate ABF conditions will help identify backfeeding protectors and expedite the feeder restoration process. This will lead to lower operational costs.

Finally, the 3rd generation transmitter provides indication of transformer oil level which is critical to the safe and reliable operation of the transformer. Oil leaks can result in low oil levels, leading to catastrophic failure. 3rd generation transmitters report low oil level conditions with sufficient time so that the transformer can be replaced or refilled prior to failure.

Supplemental Information:

- Alternatives: An alternative to the installation of 3rd generation RMS transmitters would be to leave the existing transmitters in place. Critical information on transformer oil level would not be available and acted upon thus impacting system reliability.

- Risk of No Action: Failure to install new equipment may result in lower RMS reporting rates which can lead to RPM penalties described in the justification. In addition, transformers which do not report due to a failed transmitter can lead to safety and reliability implications, since no transformer data is available to warn of impending catastrophic failure.

- Non-financial Benefits: Non-financial benefits include increased public and worker safety, reduced risk of oil spills (environmental impact), and increased feeder reliability due to reduction in transformer failures.

  A 3rd generation transmitter allows for a more reliable send out of critical RMS transformer and protector information used for load flow studies and modeling. In addition, the RMS information is used by control center operators to make operating decisions based on system conditions.

- Summary of Financial Benefits (if applicable) and Costs: The installation cost for a 3rd generation transmitter, including material and labor, is approximately $3k. A leaking transformer without oil level information would have to be replaced during an unscheduled emergency outage if it fails. The cost for an in-service transformer, emergency replacement is approximately $130k.

  In addition, studies show that having a reverse power flow indication saves approximately 3 hours per ABF condition. Con Edison's feeders experience an average of 700 ABF conditions annually. A three hour savings per ABF can provide $350k of operational savings per year.

- Technical Evaluation/Analysis: The 3rd generation transmitter provides greater reliability in comparison to the previous generation of transmitters. The additional oil level and ABF indicator functionality will reduce the risk of catastrophic failure. 3rd generation transmitter units can be more effectively tracked, as serial number and manufacturing information is transmitted remotely. See the justification section for further detail.

- Project Relationships (if applicable): Pressure Temperature and Oil Sensors

- Basis for Estimate: The basis for the estimate for this program is the historical unit costs of installation of a 3rd generation RMS/PTO transmitter.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,370	866	1,681	1,125		1,274
M&S	1,510	465	2,069	1,141		1,321
A/P	320	33	515	34		18
Other	(267)	773	56	1		11
Overheads	1,900	1,018	1,945	1,057		1,034
Total	**1,370**	**866**	**1,681**	**1,125**		**1,274**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	759	957	957	957	957
M&S	782	986	986	986	986
A/P	111	139	139	139	139
Other	69	87	87	87	87
Overheads	836	1,053	1,053	1,053	1,053
Total	**2,557**	**3,222**	**3,222**	**3,222**	**3,222**

X	Capital
	O&M

2019– Central Operations/Substation Operations

Project/Program Title	Retrofit Overdutied 13kV and 27kV Circuit Breaker Programs.
Project Manager	Nicalos Graham
Hyperion Project Number	PR.0ES1300
Status of Project	Ongoing
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Regulatory Mandated

Work Description:
This program provides funding to replace a number of existing 13 & 27 kV circuit breakers installed in Con Edison's substations that currently are not rated to interrupt maximum fault. Circuit breakers will be replaced where the maximum fault current exceeds their rating.

It is currently a 2017 Con Edison rate plan requirement to perform a minimum of 50 13kV or 27kV breaker retrofits per calendar year, and complete an average of 60 per year within a 3 year period (2017-2019). The Company currently targets a combined total of 60 breaker replacements per year, which allows for the maximum number of replacements per year within the delivery and resource constraints associated with this equipment.

Stations currently in progress, or projected to be in progress by 2018 include E63rd St., Parkchester #1, Jamaica, Brownsville #1 & #2, Ave. A, and Cherry St.

Justification Summary:
Based on a 2005 analysis performed by the Company and verified by an independent consultant (ABB), fault currents exceed breaker interrupting capability at 35 area substations. The analysis assumes a worst-case scenario based on all the equipment in the station being on line, a failure occurring across all three phases at or near the station switchgear, and perfect conductivity between the phases at the failure point.

Con Edison established a long-term system enhancement program to replace and/or upgrade all of the 13kV and 27kV circuit breakers. Under this program, the first priority is given to the stations where the potential of over-duty is 10% or greater. The second priority is given to the substations where the potential over-duty is between 3% and 10%. Finally, the substations with less than 3% potential over-duty are being addressed as the third priority.

In addition, upgrading the existing equipment with state-of-the art, modern, rack-out type circuit breakers will provide the capability to interrupt fault currents and maintain system integrity. Completing these retrofits now will help meet reliability standards, lower life-cycle costs and reduce forced outage rates. Additionally, this will extend the service life of the existing switchgear.

Supplemental Information:

- Alternatives: Two alternatives were considered:
  - Complete switchgear replacement – Discontinued due to it is cost prohibitive. Average cost of $235K/position for retrofit vs. $750K/position cost for replacement. Replacement is also time consuming and compromises reliability for the duration of replacement.
  - Install a fault current limiting device at substations that are over duty – while there has been some research & development activity in this area, currently there is no commercially available device that meets system design requirements.

- Risk of No Action: Equipment failure is possible if not replaced.

- Non-financial Benefits: Once stations are fully upgraded, it removes a potential barrier for Distributed Generation interconnection with networks supplied by the station. In addition, at certain stations replacement of the existing breakers with smaller, lighter, modern breakers allows for one person switching.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: The earlier vintage 13kV and 27kV circuit breakers at Con Edison substations have fault current interrupting ratings ranging from 20kA to 40kA in the 13kV Area Substations and 30kA to 40kA in the 27kV Area Substations. Switchgear and circuit breakers currently available on the market have a fault current rating of 63kA at 13kV and 44kA at 27kV. The review of system fault currents at the area substations in the Con Edison system has indicated that for certain 13kV and 27kV circuit breakers, the available fault current exceeds the nameplate interrupting rating. The switchgear bus, associated insulation, and protection equipment have been evaluated by Engineering and are within the fault current rating of 63kA for 13kV switchgear and 44kA for 27kV switchgear.

- Project Relationships (if applicable): N/A

- Basis for Estimate: Funding request is based on Engineering estimates for stations currently in progress, or expected to start in 2017.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,892	970	1,458	2,426		3,639
M&S	4,700	2,818	3,296	4,314		3,078
A/P	1,997	166	631	638		664
Other	23	28	5	(519)		114
Overheads	4,657	2,693	2,193	3,172		4,555
Total	**13,269**	**6,674**	**7,583**	**10,031**	**-**	**12,050**

Future by Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	2,182	2,817	2,817	2,375	2,375
M&S	4,823	5,726	5,781	4,925	4,875
A/P	1,171	1,512	1,512	1,275	1,271
Other	192	248	259	220	219
Overheads	3,132	4,527	4,461	3,705	3,760
Total	**11,500**	**14,830**	**14,830**	**12,500**	**12,500**

X	Capital
	O&M

2019 – Central Operations/ Substation Operations.

Project/Program Title	Roof Replacement Program.
Project Manager	Charles Davoren
Hyperion Project Number	PR.2ES8200
Status of Project	Ongoing
Estimated Start Date	N/A
Estimated Completion Date	N/A
Work Plan Category	Strategic

Work Description:

This program provides replacement of roofing on buildings and major equipment at our substations, pumphouses and pressurizing plants, where the roofing has deteriorated or when leaks are found. The Company has an ongoing program to inspect each of the 554 roofs approximately once every five years (more frequently for older roofs, less frequently for newer roofs), averaging 100 roofs per year. A large number of our facility roofs have deteriorated, and have been repaired numerous times. The roof inspection program reveals which of our roofs have deteriorated beyond repair. Roofs are replaced when needed. Typically the two types of roof systems used are ethylene propylene diene monomer (EPDM) and Kemper. EPDM roofs consist of a rubber membrane adhered to rigid insulation which is fastened to the existing roof deck. The Kemper system consist of a primer applied to the existing roof deck then a fleece layer saturated with polyester resins. Removal of existing roofing materials will also assure any asbestos issues, if present, are alleviated.

The Company has an ongoing program to inspect each of the 554 substation roofs approximately once every five years (more frequently for older roofs, less frequently for newer roofs), averaging 100 roofs per year. These inspections identify candidates for the capital Roof Replacement program as well as potential repairs where applicable. This O&M program would address the repairs that would alleviate current deteriorated roofs which are not currently candidates for a full replacement.

Central Engineering has also established an inspection program to monitor and assess the structural condition of substation facilities (external and internal) to ensure safe conditions for members of the public, company employees and the equipment housed in the facilities. This request proposes the establishment of a comprehensive maintenance program to correct material issues which can no longer be addressed through routine maintenance. The impacted areas include major sections of the structure, both interior and exterior, that are too significant to be addressed with minor repairs.

Justification Summary:

This work is required to avoid permanent damage to equipment, accelerated structural deterioration and personal safety hazards. Delay in roof replacements when needed increases the likelihood of these events.

Supplemental Information:

- Alternatives: Repair existing roofs. This alternative would be a temporary solution at best and repairs would increase in scope and cost on an annual basis. For roofs with a certain rating, as discussed below in the Technical Evaluation, it provides an unacceptable service life and does not eliminate the potential operational and safety concerns. Another less desirable alternative for this program is to cover with tarps. This approach is not recommended as prolonged exposure to the elements will result in water intrusion that will consequently result in further degradation of the roofing system. Since equipment housed within the substation buildings is not designed to be exposed to the elements, water intrusion will adversely affect the equipment, thereby affecting system reliability.

- Risk of No Action: This work is required to avoid permanent damage to equipment, accelerated structural deterioration and personal safety hazards.

- Non-financial Benefits: Increased reliability of equipment and facilities, eliminating possible inadvertent trips including outages to equipment and customers, and reduced personal safety hazards.

- Summary of Financial Benefits (if applicable) and Costs: This program will remove the need to make repeated O&M repairs to these roofs.

- Technical Evaluation/Analysis: In order to provide reliable service, we must maintain our electric delivery facilities in good working condition and toward that end have continued the roofing program. This program is committed to inspecting each of the 554 roofs every five years (more frequently for older roofs, less frequently for newer roofs), averaging 100 roofs per year, and to repair or replace roofs as needed. The results from the roof inspections determine if a particular roof can be repaired or needs to be replaced. The roofs are rated on a standardized 1-9 scale, with 1 being a roof in excellent condition and 9 being a roof requiring immediate attention. Roofs scoring 7 or above are scheduled for replacement, all others are repaired as required. Generally, roofs scoring below a 7 can be effectively repaired to address issues found. Repairs are short term fixes that will extend the life of the roof by a few years. Replacement roofs are typically good for 20 years. Typically, roofs requiring replacement are not candidates for repair, except on an emergency basis.

RATINGS DESCRIPTION

1. New Roof 1 to 2 years old, no work needed.
2. Roof more than 2 years old, no work needed.
3. Roof has no leaks, less than 5% of the roof area to be repaired. This also includes repairs to gutters, drains, leaders, and painting of metal roof and debris removals.
4. Roof has no leaks, 5-10% of the roof area needs repairs.
5. Roof has no leaks, 10-20% of the roof area needs repairs.
6. Roof has leaks; up to 20% of the roof area needs repairs.
7. Roof has leaks; up to 40% of the roof area needs repairs.
8. Roof leaks and requires replacement. No structural damage to deck or framing.
9. Roof leaks are bad and roof requires replacement. Structural damage to deck and/or framing is present and represents a hazard to occupants and equipment.

Water intrusion due to roof leaks can result in equipment damage and affect substation reliability. Standing water on floors and roofs causes slippery conditions and electrical hazards that are personnel safety concerns. Prolonged exposure to water intrusion causes concrete spalling, corrosion of rebar, and degradation of the structural integrity of the building. The installation of new roofing will eliminate leaks and the operational and safety hazards associated with water intrusion and accumulation.

- Project Relationships (if applicable): NA

- Basis for Estimate: Near term work is based on Engineering estimates based on similar types of work done in the past. Outer term work is based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature. The current unit cost for roof replacement is $30 per square foot for EPDM roofs and $65 per square foot for Kemper roofs. Historically, we have replaced 12-15 roofs per year.

  The operations and maintenance expense is estimated to address five roof repairs (~$30K) and one façade projects (~$500K) per year.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2017
Labor	134	117	178	178		449
M&S		12	10	19		0
A/P	554	201	1070	1,019		1,751
Other	1	(10)	14	276		6
Overheads	316	190	448	538		665
Total	**1,005**	**510**	**1,720**	**2,030**	**-**	**2,871**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	280	281	281	275	277
M&S	140	117	128	160	149
A/P	1,026	1,005	1,006	957	957
Other	143	117	115	149	148
Overheads	532	607	597	586	596
Total	**2,120**	**2,127**	**2,127**	**2,127**	**2,127**

X	Capital
	O&M

2019 – Central Operations / Substation Operations

Project/Program Title	RTU Upgrade Program
Project Manager	Seda Steck
Hyperion Project Number	PR.20987016
Status of Project	In Progress
Estimated Start Date	2014
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Remote Terminal Unit (RTU)

Work Description

The scope of this project is to upgrade the existing area stations Remote Terminal Units (RTU). Currently there are 3 variations of RTUs installed in area stations, Tejas, Quindar (QEI), and Systems Northwest (SNW). The Tejas and Systems Northwest type RTUs will be upgraded with a new Schneider Electric SAGE 2400 or 4400 processor, which will replace the card frame assembly while maintaining some existing hardware. All the Quindar RTU hardware will be completely replaced with the Schweitzer Engineering Labs (SEL) AXION RTAC platform.

For the Schneider Electric application, the upgraded RTU will be functionally equivalent to the existing unit. The field wiring for the status and analog panels will be left untouched and undisturbed. The field wiring to the Relay Control Output panels will not be modified in any way. It will be simply lifted from the existing Control Relay Panels and then reconnected onto the new Relay Panels using the same wire landing positions.

For the Quindar RTUs, the existing RTU cabinet will be reused and no new external wiring will be run. The new SEL RTU will replace all internal hardware and will be wired to the existing terminal blocks in the panel with the external connections. The SEL RTU come with a built in HMI and has the option to replace the mimic board if desired.

Communications to the Energy Control Center (ECC) will use the existing frame relay communication devices, which will be left in place. Two serial ports from the new RTU will connect to the redundant frame relay units. The point mapping will be replicated in terms of the ordered lists of status, analog and control points but the upgraded RTU will be configured to use DNP3.0 protocol instead of the L&G protocol currently in use. The ECC database for the upgraded RTU will be reconfigured for the DNP3.0 protocol.

Due to the short amount of time required to complete the Tejas/SNW retrofits, several can be done per year. The work is discretionary based on which station is more critical. A high level schedule would be about 3 months for procurement, 1 month for design, and 1 week for construction.
The QEI RTU replacements have added work in rewiring all the internals of the cabinet, therefore it is much more work to complete. A high level schedule would be about 1 months for procurement, 2 months for design, and 5 weeks for construction.

The plan is to target 30 substations total; and completing 2 substations per year. The stations that have yet to be completed are:

Substation	Location	RTU Type
Corona #1	Queens	Tejas
Corona #2	Queens	Tejas
Glendale	Queens	Tejas
Sherman Creek	Manhattan	Tejas
Buchanan	Westchester	Tejas
Washington St	Westchester	Tejas
Cherry St	Manhattan	Tejas
East 63rd St #1	Manhattan	Tejas
East 63rd St #2	Manhattan	Tejas
East 75th St	Manhattan	Tejas
Leonard St #1	Manhattan	Tejas
Leonard St #2	Manhattan	Tejas
West 65th St #1	Manhattan	Tejas
West 65th St #2	Manhattan	Tejas
Parkchester #2	Bronx	SNW
Woodrow	Staten Island	SNW
East 40th St #2	Manhattan	SNW
Bruckner	Bronx	QEI
Cedar St	Westchester	QEI
East 36th St	Manhattan	QEI
East 40th St #1	Manhattan	QEI
Harrison	Westchester	QEI
Hellgate	Bronx	QEI
Millwood West	Westchester	QEI
Ossining	Westchester	QEI
Plymouth	Brooklyn	QEI
Seaport #2	Manhattan	QEI
Wainwright	Staten Island	QEI
Water St	Brooklyn	QEI
Willowbrook	Staten Island	QEI

Justification Summary:
There are currently 14 Tejas and 15 QEI RTUs installed in various Area Substations. These units have been in operation for 30 to 45 years. They are based on an old design and are experiencing component failures at a gradually increasing rate. Con Edison has run out of spare units for some of the component types used in these RTUs.
The original equipment vendor, no longer exists as an entity, or does not supply parts for these RTUs. Due to the age of these RTU units, and that many of the board level components used in its design are obsolete, it is no longer possible to obtain new spares or to repair boards that have failed.

The unavailability of spare replacement parts leaves Con Edison vulnerable to future failures. Any other RTU components that fail in the future will either degrade the RTU functionality or totally shut the RTU down (as in the case of a processor failure, for example). This risk needs to be eliminated and/or mitigated.

Recently we have had failures of these units at various different stations some of them were able to be repaired, but not without significant down time. Other stations are currently in the replacement process, at which point its spare parts can be used. This is expected to continue until all units have been upgraded.

Supplemental Information:

- Alternatives: The alternative would be to replace each RTU as it fails. During the time in which a replacement is procured, the station will not be controlled by the ECC. This means that the station will have to be staffed for 24 hours a day. Due to how long it might take for the manufacturer to build the replacement unit, it could be months before it is replaced. This is not recommended.

- Risk of No Action: No action can result in an unexpected and unprepared RTU failure. It would result in the station having to be staffed for 24 hours a day until it is replaced.

- Non-financial Benefits: The non-financial benefits include increased reliability and efficiency.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: NA

- Project Relationships (if applicable): NA

- Basis for Estimate: Prior work of a similar nature was used in developing the order of magnitude cost analysis. Material and equipment costs are based on recent purchase orders for similar material & equipment.

GE HUMAN MACHINE INTERFACE

Work Description:
This project will replace GE Human Machine Interface (HMI) systems with up to date hardware and software that is in compliance with the standard used by the Electrical Control Systems (ECS) group. The new HMI system will contain substation hardened equipment, designed for both robustness and redundancy, to limit the likelihood and impact of a component failure. The HMI includes; the station one-line with breaker indications and controls, metering values and alarms of critical equipment. It is used by the substation operator for monitoring of the substation.

The 7 GE area substations where these replacements will take place are:

- Seaport 1
- Murray Hill
- Grasslands
- Mott Haven
- Rockview
- Parkview
- Astor

<u>Justification Summary</u>:
Recently, several of GE HMI systems at substations (such as White Plains, Mott Haven and Trade Center, etc.) have begun to exhibit hardware and software failures, e.g. "Stale Data Alarm". Nine stations contain systems of a similar build and age and it is expected that additional failures will follow.

When an HMI failure occurs (e.g. issue with "stale" data), it requires a reboot of the HMI server or in more severe cases, a power cycle of the physical server. A HMI system failure reduces or eliminates the ability of the SCADA system to transmit data, which has a significant impact on substation operations.
In such cases, the station has to be controlled manually in coordination with the ECC. Meanwhile, the operators cannot be certain that the HMI is properly reporting all alarms, indications, and controls.

The new system will provide reliable, safe, and secure control and supervision for the power substations, and allow for its unmanned operation. The new Automation System will communicate with existing protection Intelligent Electronic Devices IEDs, Input / Output hardware, and the Energy Control Center (ECC). The new Web-based HMI system will be designed as open architecture, and modular, comprising only of standard elements performing standard functions and using certain communication protocols.

<u>Supplemental Information</u>:

- <u>Alternatives:</u> The alternative would be to maintain the existing HMI systems. Maintaining the existing systems does not address the ongoing issues because they are caused by obsolescence. As such, the company could expect to continue to see periodic HMI system failures. These failures reduce the reliability of substation data provided by these devices, requiring the relevant substation to be manned full time. In addition, these HMIs lack manufacturer support (e.g. Windows 2000/XP operating system is no longer supported), and lack of spare parts, such as PLA viewer workstation HDD, which is no longer available. For these reasons, continuing to maintain the existing GE HMIs is not recommended.

- <u>Risk of No Action</u>: HMI system failures reduce or eliminate the ability to access critical substation information, which impacts substation operations. In such instances, the station has to be controlled manually as well as from the ECC. Meanwhile, the operators do not receive critical information about whether the substation is properly reporting all alarms, indications, and controls.

- <u>Non-financial Benefits</u>: Ensure ECC accurate and effective monitoring and control of substations. Outage times and maintenance costs associated with the new web-based HMI system will also be reduced significantly. The substation operators will have new graphic displays connected to the HMI computer which will display equipment status, control, alarming, and metering.

- <u>Summary of Financial Benefits/Costs</u>: NA

- <u>Technical Evaluation/Analysis:</u> The replacement of the GE HMI systems will improve substation functionality and reliability by providing the station operator with modern state of the art units. The new HMI system will contain substation hardened equipment, designed for both robustness and redundancy, to limit the likelihood and impact of a component failure.

- <u>Basis for Estimate</u>: Overall funding request estimate based on engineering estimate done for one of the targeted stations. The average cost is approximately $1,200 per unit, and budgeted for two replacements per year

Annual Funding Level ($000):

Historical Elements of expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	494		26
M&S	4	-	-	623		10
A/P	-	-	-	522		-
Other	-	-	-	78		6
Overheads	4	-	-	636		19
Total	**8**	**-**	**-**	**2,353**		**61**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	60	648	784	753	753
M&S	60	575	708	692	682
A/P	12	130	157	151	151
Other	5	65	78	75	75
Overheads	63	742	885	839	849
Total	**200**	**2,160**	**2,612**	**2,510**	**2,510**

X	Capital
	O&M

2020 – Electric Operation

Project/Program Title	Shunt Reactors
Project Manager	Robert Szabados
Hyperion Project Number	PR.5ED1201, PR.9ED3261
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
This program is for the installation of Shunt Reactors on primary feeders to provide compensation within the Brooklyn/Queens and Staten Island load areas where feeders have been determined to need compensation.

Units per Year:
The plan in Brooklyn/Queens will be to install approximately 12 reactors in 2019 and 2020 and approximately 18 reactors in 2021 and 2022. Currently, there are 170 feeders from a recent compensation study that require compensation and a shunt reactor. Staten Island plans to install a new shunt reactor and an upgrade in 2019 and is projected to require one upgrade and one new installation each year until the year 2022. The projected schedule is as follows:

Brooklyn/Queens

Year	Projected Number of Shunt Reactors
2019	12
2020	12
2021	18
2022	18
2023	36

Staten Island

Year	Projected Number of Shunt Reactors
2019	2
2020	2
2021	2
2022	2
2023	4

In addition to the required installations, it is estimated that two replacement units per year for each region will be required.

High-level schedule:
The goal is to have the proper compensation for each 27 KV network feeder in the Brooklyn/Queens region by 2028.

Justification Summary:
Shunt Reactors are required to be installed on selected 27kV and 33kV feeders as per Company specification EO-2069. The installation of these reactors is required in order to prevent over voltages from damaging Company and customer equipment during back feed conditions.

Supplemental Information:

- Alternatives:
  The alternative to installing shunt reactors is to deploy crews during abnormal back-feed conditions to block open network protectors in order to eliminate the over voltages. However, this does not fully protect customer equipment from damage since over voltages will persist until crews find and correct the back-feed condition.

  Installing shunt reactors limits over voltages and reduces the potential for damage to customer equipment. In addition, shunt reactor installation improves feeder processing productivity and reduces O&M costs on scheduled feeder outages.

- Risk of No Action:
  A 27 kV and 33 kV network feeder that is not properly compensated with a shunt reactor has the potential to cause over voltages on the secondary system and primary feeders during a back feed condition. The magnitude of the over voltage condition could result in more than 140 Volts line to neutral on the secondary side of the back feeding transformer, and 20% to 40% overvoltage condition on the primary back fed feeder. These overvoltage conditions have the potential to do damage to the company's equipment as well as customers' equipment.

- Non-financial Benefits:
  Customer equipment is designed to operate on 120 Volts. An overvoltage condition could cause customer equipment to malfunction in possibly dangerous ways. By installing shunt reactors, overvoltage conditions will be mitigated and customer safety will be improved.

- Summary of Financial Benefits (if applicable) and Costs:
  The cost of the program includes the installation of new vaults, installation of ducts, and the installation and splicing of new primary cable. When feasible, existing vacant vaults will be used to minimize the cost of this work. When no vacant vaults are available, a new vault will be placed as close as possible to existing manholes in order to minimize the length of the duct run and associated costs. Compensating for overvoltage on the primary feeders will also prolong the life of primary cables and transformers since they will not see excess overvoltage during their life cycle. Overvoltage conditions have the potential to lead to equipment damage at customer locations and result in a customer claim for damages and loss of use of that equipment.

- Technical Evaluation/Analysis:
  A back-feed condition in a network system is an operating problem which occurs because, occasionally, a network protector will fail to open when the network primary feeder is taken out

of service. When this occurs, the primary feeder remains alive from the network although it is de-energized at the area substation. Under this condition, the back-feeding transformer will supply the cable charging kVA of the network primary feeder and the magnetizing kVA of all the transformers connected to the network primary feeder. The network primary feeder charging kVA are the result of the cable capacitance to ground (capacitive kVA) and the magnetizing kVA are due to transformer excitation requirements (inductive kVA). For a 27 or 33 kV network primary feeder, the cable charging kVA are usually far in excess of the magnetizing kVA of the transformers connected to the feeder. As a consequence, the charging kVA that are not compensated by the magnetizing kVA will raise the voltage in the network secondary mains that supply the back-feeding transformer, particularly so in its immediate vicinity. By transformer action, the network primary feeder will also experience the overvoltage condition. It is necessary, therefore, to install shunt reactors to limit back-feed over-voltages to safe values for customer and company equipment.

- Project Relationships (if applicable):
  None

- Basis for Estimate:
  The estimate for this project is based on the historical cost of performing similar work.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	43	88	287	94		220
M&S	36	67	459	6		267
A/P	43	83	799	114		425
Other	0	9	36	-2		21
Overheads	113	190	953	107		449
Total	**235**	**437**	**2534**	**319**		**1,382**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	189.23	192	373	373	746
M&S	215.97	220	425	425	851
A/P	378.49	385	746	746	1,491
Other	16.61	17	33	33	65
Overheads	468.71	476	923	923	1,847
Total	**1,269**	**1,290**	**2,500**	**2,500**	**5,000**

X	Capital
	O&M

2019 – Central Operations / Substation Operations.

Project/Program Title	Substation Loss Contingency - Rapid Recovery of an Area Substation/Transmission Resiliency Transformers
Project Manager	John McCoy
Hyperion Project Number	21384664
Status of Project	Engineering/Planning
Estimated Start Date	January 2015
Estimated Completion Date	December 2021
Work Plan Category	Strategic

Work Description:
There are two projects included under this Program, Transmission Resiliency Transformers and Rapid Recovery of an Area Station.

Rapid Recovery of an Area Substation (PN 26141-15)
This project will provide for the purchase of equipment required for the rapid recovery of a three bank area substation with 24 dual feeder positions. Equipment includes:

a) Three Mobile Resiliency Area transformers, each rated 138/69kVpri, 58/65/93MVA KDWF, 13/27/33kv secondary
b) Three (3) 138 kV dead tank circuit breakers
c) Six (6) 38kV, 40 kA fixed position SF6 distribution switchgear sections each with one transformer breaker, one SYN bus breaker and five (5) dual pothead distribution feeder positions and accessories. Each section will be equipped with relay protection, controls and ancillary equipment (AC and DC power supplies, local HMI – control, monitoring & alarms)
d) Grounding mat
e) 35kV 3000A cable-bus
f) 138kV XLPE shielded power cable and terminations, 27kV shielded power cable and 15MVAR/27kV Capacitor Assemblies

In the event the Company incurs a loss of an area substation, this equipment would be deployed in conjunction with other operational measures which may include load management initiatives such as voltage reductions, rolling blackouts, network cutouts, temporary generator installations, and other similar temporary solutions.

Transmission Resiliency Transformers (PN 26116-15)
This project will provide for the purchase of electrical equipment (resiliency transformers, potheads, and cable) for system restoration and resiliency for the complete loss of a single transmission substation. Loss of any of the large transmission substations would result in severe issues with system power flows and stability and/or a loss of supply to a number of area substations, potentially impacting a large number of customers. Resiliency (mobile) transformers and associated trailers, 138 kV and 69 kV cables and potheads, protective system mobile trailers, and associated equipment would be required to construct an ad-hoc substation in the street adjacent to the damaged substation to restore the supply to the affected area substations.

Long lead equipment includes, but is not limited to: six (6) 100/50 MVA, 345-138/138-69 kV, single-phase mobile transformers, integrated automation/relay protection system and relay panels trailer.

Justification Summary:

Rapid Recovery of an Area Substation / Substation Loss Contingency

The loss of a single area substation would result in a significant interruption of electric service to our customers. Much of the focus of the work at area substations has been on reducing the risk of the likelihood that a catastrophic loss would occur. Capital and O&M programs such as the preventive maintenance program, breaker replacement program, security programs and procedures, pumping plant improvement program, and storm hardening efforts all address this risk.

Recent weather events, equipment failures and past terrorist events have shown the possibility of the extended loss of an area substation. These include flooding, fire, and a building collapse (9/11/2001). Additionally, the 2013 attack on the Metcalf utility substation in California increased concern about physical attacks. In some of these instances, the customers supplied by the failed substation were restored to service from mobile generators or shunts from physically adjacent area substations.

A review of all of our area substations shows the ability to restore customers by using portable generation or transfers to a nearby area substation is not always feasible due to the station loading, distance or impracticality due to the amount and locations of shunts and/or mobile generators that would be required. As a result, alternate sources of power to restore must be developed. In response to a loss of an area substation for 24 hours or longer at some of our area substations, the only means to quickly restore electric service to all of the customers affected includes the construction of a rapid deployment area substation in the vicinity of the failed substation. The resiliency area transformers and mobile switchgear are for use at any of the 64 area substations, with a higher priority application for 27kV double-syn-bus stations in Brooklyn and Queens, and partial applications in the Bronx.

Transmission Resiliency Transformers / Substation Loss Contingency

Large transmission substations interconnect circuits to form the transmission grid, sending and receiving power, transforming voltages, and directing flows so that the circuits operate within their current carrying capacity and voltage limits. Potential causes of the loss of transformers include items such as weather events like significant flooding or wind, a fire or building collapse at a property adjacent to a substation, or acts of terrorism or vandalism.

The Company's current spare transformer philosophy ensures that we have at least a 90% probability of having a spare when a failure occurs. The number of spares is determined using a Poisson probability distribution function considering the number of in-service transformers, failure rates, and lead times for replacements. This philosophy ensures that we have sufficient spare transformers on-hand for historical type failures, not high-impact low-frequency (HILF) events. To recover from HILF events, dedicated equipment will be required.

The resiliency transformers are for use at any of the 33 transmission substations. The loss of any of these transmission substations would result in severe issues with system power flows and stability and/or a loss of supply to a number of area substations that serve critical load in our service territory potentially impacting a large number of customers.

Supplemental Information:

- Alternatives: The alternative solution considered was to reduce the size of the networks and/or build additional new area substations and transfer load accordingly. This is not viable or cost effective because too many new area substations would have to be built at a very considerable cost.

- Risk of No Action: System power flow control issues, system reliability concerns, and/or possible outages at multiple area substations resulting in a significant number of customer outages for an extended period of time. This is not recommended due to the potential inability to maintain reliable system power flows, or the inability to restore electric service to all of our affected customers during a loss of one or multiple substations.

- Non-financial Benefits:
  Rapid Recovery of an Area Substation / Substation Loss Contingency
  The project addresses the current inability to quickly restore power to customers following the loss of an area substation for 24 hours or longer in instances where it is either impractical or not viable to restore electric service via typical distribution solutions (generators, shunts, switching). In such cases, a new rapid deployment area substation will be installed adjacent to the failed substation to restore power to those customers not able to be restored via other means.

  Transmission Resiliency Transformers / Substation Loss Contingency
  The project addresses the current inability to quickly restore reliable power flows through one or more area substations during certain catastrophic events. In such cases, these new transformers would be dispatched to the transmission stations to restore reliable power flows, or to feed area substations in order to restore power to those substations, hence to the customers supplied by those area substations.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: A technical study to evaluate the loss of each area substation for 24 hours or longer has been updated by Electric Operations / Regional Engineering. It is estimated that five stations need a rapid deployment solution, and a rapid deployment station may be the most viable solution since a distribution solution is estimated to take longer. Additionally, the complete loss of any of our 11 double area substations likely requires a distribution solution and a rapid deployment solution to pick up the two substations. Finally, Electric Operations / Regional Engineering is reviewing the ability to restore a substation with the likely availability of emergency diesel generators during a “blue sky” day. Generator availability has been reviewed with our vendors and was identified to be lower than anticipated, thus it is likely the number of stations needing a rapid deployment solution will increase. That being said, although technical solutions exist for each station, there are multiple cases where the solution is not readily feasible or practical due to various reasons as previously noted.

- Project Relationships (if applicable): N/A

- Basis for Estimate: Resiliency Transformers – Approved Appropriation Estimate; Loss of an Area Substation - Order of Magnitude Estimate

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	6	377	768		705
M&S	-	3,632	8,527	15,479		3,381
A/P	-	26	103	626		64
Other	-	8	97	619		0
Overheads	-	1,096	2,263	4,084		1,155
Total	-	**4,768**	**11,367**	**21,576**		**5,306**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	117	-	891	-	-
M&S	1,801	-	13,136	-	-
A/P	26	-	194	-	-
Other	40	-	286	-	-
Overheads	557	-	4,867	-	-
Total	**2,540**	-	**19,374**	-	-

X	Capital
	O&M

2020 – Central Operations / Substation Operations.

Project/Program Title	Stabilization of Pothead Stand Supports/Settlement.
Project Manager	Steve Bryan.
Hyperion Project Number	PR.2ES4302
Status of Project	In Progress – Monitoring Phase
Estimated Start Date	2007
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
This is a multi-year project to correct equipment settlement problems at all substations. The project is being completed in stages. The scope of work typically includes stabilizing pothead and disconnect switch stands, prefabricated concrete control cable trenches, junction boxes, and direct buried conduits.

The Corona substation was constructed on reclaimed land. Many of the structures and buried facilities are settling, resulting in damage to foundations, troughs, conduit, splice boxes, and cable. Continuous settlement over time has caused damage to substation equipment.

While this program originally addressed issues only at the Corona Substation, we have also found that similar settlement issues are present in Astoria East and Queensbridge, and will use this program funding to address issues at these stations as well.

Due to continued settling, installation of trenches is the first required action to allow for the replacement of existing control cables affected by the current settlement. This trench system is required to mitigate the problem created by equipment foundation settlement. We use helical screw piles and continuous concrete-grade beams to support the trench.

Justification Summary:
A settlement study was performed by Muser Rutledge Corporation to determine if settlement will continue or if we have reached the end of settlement. Their report states that the ground surface settlement will continue to occur as the result of secondary compression of organic, marsh soils immediately beneath site fills, but at a decreasing rate.

In 2012, we identified several similar settlement issues at the Astoria East and Queensbridge substations. We have begun to study the extent of the settlement issues at these stations, but anticipate the result will be to perform similar mitigation at the aforementioned stations as well. Corona has already experienced issues with disconnect switch mis-alignment due to ground settlement, as well as continued leakage at several points on its bus enclosures.

If the disconnect switch stands, junction boxes and conduits are not reinforced they will continue to bend and will eventually cause the disconnect stands to sink. The bus conductor becomes misaligned, and cables and conduits will break away from the control cabinet junction boxes. This would force unscheduled outages at the station, jeopardize the integrity of the equipment and the station, and create safety issues for the employees working at the station.

Supplemental Information:

- Alternatives: Increase the size of the existing footings to further spread out the structural loads in the surrounding soil. This alternative was rejected because it will only decrease the rate of settlement, but not prevent it.

- Risk of No Action: The stabilization of the disconnect switch stands, junction boxes and conduits is required to prevent further bending and damage to the existing electrical conduit risers that connect to the equipment. If the disconnect switch stands, and junction boxes and conduits are not reinforced, they will continue to bend and will eventually cause the disconnect stands to sink. The bus conductor becomes misaligned, and cables and conduits will break away from the control cabinet junction boxes. This would force unscheduled outages at the station, jeopardize the integrity of the equipment and the station, and create safety issues for the employees working at the station.

- Non-financial Benefits: This program will improve overall system reliability by reducing operational issues with equipment, primarily disconnect switches, at the affected stations.

- Summary of Financial Benefits (if applicable) and Costs: This program is expected to reduce the costs for ongoing maintenance issues caused by settlement on affected pieces of equipment.

- Technical Evaluation/Analysis: A settlement study was done at one substation and is mentioned in the justification summary. The plan moving forward is to monitor foundations at the three mentioned substations to determine what movement is active and stabilize them.

- Project Relationships (if applicable): The Disconnect Switch Replacement Program and Area Reliability Projects are influenced by this program. These projects work in conjunction with each other, i.e., if equipment to be replaced is sitting on settled foundations, then the two scopes would have to be coordinated.

- Basis for Estimate: Funding request is based on historic settlement work that has been previously completed, and is of a similar nature to the work planned in the future. Between 2007 and 2013, the stabilization of disconnect switches 9N8, 9N9, 10N9 and HF8 was completed. During the same time frame, the stabilization of pothead stand supports for Feeders 18001 and 18002 was completed.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	412	688	700	700
M&S	-	345	588	582	575
A/P	-	210	350	350	345
Other	-	30	49	49	51
Overheads	-	503	825	819	829
Total	**-**	**1,500**	**2,500**	**2,500**	**2,500**

X	Capital
	O&M

2019 Capital - Central Operations / Substation Operations.

Project/Program Title	Structural and Infrastructure Upgrades
Project Manager	Dan Brown.
Hyperion Project Number	PR.0ES3100
Status of Project	In-Progress
Estimated Start Date	N/A
Estimated Completion Date	N/A
Work Plan Category	Strategic

Work Description:
Finally, Central Engineering has established an inspection program to determine the structural soundness of substation facilities (external and internal) to ensure public and employee safety as well as the integrity of equipment protection contained within substation facilities. This request proposes the establishment of ongoing Capital and Maintenance Programs to correct issues that can no longer be addressed through routine maintenance. The impacted areas range from major sections, both interior and exterior, to the entire structure. The ongoing program will include addressing three to four initiatives per year for maintenance and one to two Capital initiatives per year. Work will be optimized and prioritized based on the inspection results and criticality.

This program funds facility improvements and upgrades at individual substations. The following types of facility structural improvements are covered under this program:

- Façade
- Foundation
- Retaining Walls
- Lifts and platforms
- Floors
- Heating and Ventilation
- Lighting
- Plumbing (i.e. backflow preventers)
- Large scale drainage modifications
- Paving
- Fencing
- HVAC
- Elevators and Access/Egress

Projects Projected for 2019-2022

The table below contains a listing of candidate Structural and Infrastructure Improvement Projects. Other similar projects may be added to future candidate listings. The final mix of projects to be funded will be based on project priority and availability of both engineering and the working groups' resources

Sub-Type	Location	Description	Estimated Cost ($)
Plumbing	Various	Install Backflow Preventers on Water Supplies	3,190,000
Yard Imp	Farragut	Replace Sidewalks & Curbs and Install Bollards	1,285,000
Access/Egress	WTC	Transformer Vault #1 Exit Door	571,000
Expansion	Corona	SSM & PST Building	5,000,000
Yard Imp.	E. 40th St.	Install New Hinges, Springs, & Rollers on the Roof Top Smoke Hatchways TR 1, 2, 3, 4, 5 & 8	1,000,000
Drainage Modifications	Fox Hills	Drainage Improvements - Ph 1: Flood Wall & Ph2: Storm Water Detention System.	1,200,000
HVAC, Heating & Ventilation	Various	Heating & HVAC Upgrades	2,625,000
Lighting	Various	Lighting Upgrades	2,440,000
Expansion	Fresh Kills	Building Workout Location	2,800,000
Electrical	Dunwoodie	Electrical Gallery Upgrade	1,700,000
Yard Imp	Corona	Corona Sidewalk Repair	2,154,000

To date, temporary measures have been incorporated to ensure protection of the public, employees and equipment. The issues going forward require longer term plans and solutions to correct identified conditions.

Justification Summary:

These projects are necessary to improve and maintain substation facilities in order to ensure safe and reliable operations and are not covered by other Capital Programs. In addition, these projects will enable the Company to discontinue the use of temporary office facilities, which will support continued efficient deployment of personnel and will provide employees a safer and more professional work environment.

The structural inspection program will address issues stemming from the vintage of the stations, as opposed to the current alternatives and solutions, which consist of temporary measures. The temporary measures address the current safety issues and equipment protection, however, problems continue to expand and increase in scope. In addition, the cost to maintain these temporary measures continues to increase and ultimately neglects to address the root cause of the problem. Maintenance and replacement is required based on the condition and age of the structures within the scope of this project, all of which were built between 1948 and 1991.

Supplemental Information:

- Alternatives: Substation Operations has various office facilities that are temporary in nature, currently housing numerous employees on a daily basis. The first alternative is to relocate employees currently working in these temporary locations to existing facilities, where required improvements and additional space would have to be made. In addition, where sufficient space is unavailable, new space would need to be leased or developed. Some combination of all 3 previously mentioned options may be required to most efficiently and cost-effectively relocate employees to permanent facilities. This program also funds a project to install backflow preventers on water supplies designed to bring existing substations into compliance with current cross control connection device codes and New York State and New York City requirements. As non-compliance locations are identified, a scope of work for each facility is developed and a construction cost estimate determined.

- Risk of No Action: The risk of no action is that the continued degradation of facilities could lead to hazardous conditions that impact equipment reliability and the safety of company personnel and the public.

- Summary of Financial Benefits/Costs: N/A

- Non-Financial Benefits (if Applicable): This program provides employees a safe and professional work environment and ensures a safe and reliable operation of the substations.

- Technical Evaluation/Analysis: N/A

- Project Relationships (if Applicable): NA

- Basis for Estimate: The program's funding request is based on the engineering estimates for the projects currently in progress.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,329	563	777	1,617		1,055
M&S	227	378	687	1,544		753
A/P	2,328	761	486	1,042		2,418
Other	104	80	11	36		39
Overheads	2,248	967	930	1,894		1,372
Total	**6,236**	**2,749**	**2,891**	**6,133**		**5,637**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,565	2,196	2,653	2,726	2,726
M&S	915	1,182	1,428	1,467	1,467
A/P	503	722	873	896	897
Other	89	132	197	239	207
Overheads	1,503	2,333	2,781	2,822	2,853
Total	**4,575**	**6,564**	**7,932**	**8,150**	**8,150**

X	Capital
	O&M

2019 – Central Operations / Substation Operations

Project/Program Title	Substation Enclosure Upgrade Program.
Project Manager	Renee Jaikaran
Hyperion Project Number	PR.23287694
Status of Project	In-Progress.
Estimated Start Date	N/A
Estimated Completion Date	N/A
Work Plan Category	Strategic.

Work Description:

This program will upgrade selected outdoor enclosures throughout the system by providing weatherproof canopies for switchgear cubicles & relay cabinets. This is typically supplemented with sealing existing metal enclosures with a sealing material (typically Kemper Seal) or providing the installation canopies as long term solution. In some cases, cubicle doors are replaced or refurbished, the enclosure structural supports are reinforced, or other steel/sheet metal work is performed to preclude deterioration of the while providing for safe inspection, maintenance, and repairs under most weather conditions.

The installation of the canopies is a long-term solution to protect relay cabinets & switchgear cubicles from inclement weather and enhance the reliability of the electric system.

The canopies will consist of a structural frame with a roof and siding to protect the top and upper sides of the cabinets. In some cases, the canopy frames can be mounted onto the existing relay cabinet foundations. Presently, the following facilities are targeted for relay canopies construction:

- Rainey (1 Canopy)
- Fresh Kills Substation (4 canopies)
- Dunwoodie Substation (6 canopies)
- Queensbridge (8 canopies)
- Corona Relay Houses Relay house (6 Canopies(A,B,C,D,E,F)
- East 75th street Switchgear SG/Sect5 (Associated with T5E)

Justification Summary for Switchgear Cubicles:

The switchgear cubicles in a number of substations require upgrading. These outdoor switchgear housings have been weathered by exposure to the elements. Their construction is typically a painted sheet metal enclosure resting on a concrete slab. Many steel components are corroded. The exterior doors no longer close and seal correctly. Many slabs are deteriorated and do not allow proper drainage accelerating corrosion of the structural supports. Lastly, for some enclosures, the roofs leak.

The upgraded enclosures will reduce weather intrusion related trip outs, unscheduled outages, and alarms.

Justification Summary for Relays:

Relays are usually housed in heavy gauge steel cabinets designed to be water tight. When these steel cabinets are exposed to weather, they will deteriorate with time. In various substations, several of these outdoor relay cabinet installations are deteriorated and jeopardize the reliability of the electric system.

Relays are used to detect electrical problems or faults in transmission and area substations. When these relays detect a fault, they send a signal that operates protective equipment, such as a circuit breaker, which will isolate the fault and limit the damage. Relays will also send a signal to the control room and notify the station operator of the electrical hazard. It is important to ensure that these relays will always function because the detection of electrical problems in the substation will protect the operators in the area, limit the potential damage on substation equipment, and will minimize the number of customer outages. For these reasons, relays must be maintained in a dry and safe environment.

The metal relay cabinets are exposed to the elements and they have deteriorated over time. This has allowed water to enter the cabinets, and we run the risk of compromising the equipment and jeopardizing the reliability of the station. Installation of canopies will preclude deterioration of the relay cabinets while providing for safe inspection, maintenance, and repairs under typical weather conditions. The installation of the canopies is a long-term solution to protect relay cabinets from inclement weather and enhance the reliability of the electric system. The canopies will consist of a structural frame with a roof and siding panels attached to the frame. These frames and panels will enclose and protect the existing relay cabinets.

Supplemental Information:

- Alternatives to Switchgears Cabinets: There are two alternatives to taking steps to weatherproofing the existing enclosures. The first alternative is to replace the switch gear, which is extremely costly. The second alternative would be to enclose the station, which is also cost prohibitive.

- Alternatives for Relays House Enclosures: An alternative to the current solution is to build masonry structures to provide protection for the relay cabinets. This is a higher cost option, sometimes not feasible due to space constraints and therefore not recommended.

- Risk of No Action: Doing nothing would allow the enclosures to deteriorate thereby exposing the system to repeated outages and increased frequency of repairs and inspections and reduced reliability.

- Non-financial Benefits: This program will improve system reliability, as it will reduce the number of unplanned outages associated with trip outs from water intrusion. Enhance the reliability of equipment by protecting the relay cabinets from inclement weather.

- Summary of Financial Benefits (if applicable) and Costs: This program will defer the need to replace entire switchgear sections if they were allowed to continue to deteriorate. It will also reduce the costs associated with trip outs by water intrusion.

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable): N/A

- Basis for Estimate for Switchgear Cabinets: This funding request is based on the cost of actual work done in prior years under this program. The average cost per unit is $500, and is budgeted for one unit per year.

- Basis for Estimate for Relay Enclosures: This funding request is based on the cost of actual work done in prior years under these programs. The average cost per unit is $1,000, with one enclosure budgeted per year.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	10	-	-	813		266
M&S	23	2	-	99		141
A/P	10	5	64	72		224
Other	-	-	6	62		111
Overheads	21	3	16	628		288
Total	**64**	**10**	**86**	**1,674**	**-**	**1,030**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	345	802	662	665	665
M&S	265	527	436	437	437
A/P	184	142	126	130	123
Other	-	-	-	-	-
Overheads	361	829	676	668	675
Total	**1,155**	**2,300**	**1,900**	**1,900**	**1,900**

X	Capital
	O&M

2019 – Central Operations / Substation Operations.

Project/Program Title	Substation Transformer Replacement Program
Project Manager	C. Davoren
Hyperion Project Number	PR.2ES8000
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
The purpose of this program is to proactively replace transformers that have been assessed nearing the end of their life expectancy and cannot be maintained in a reliable operating condition. The scope of the transformer replacement includes the installation of a moat containment system for the vault, a new fire protection system, and a transformer condition monitoring system. Funding will also be used to secure future transformer orders with long lead times for future replacements identified by our asset management program.

Justification Summary:
There are 422 power transformers on the system, of which 181 have been in service for over 40 years. As these units age there is an increase in the amount of corrective maintenance and the likelihood of malfunction. Replacement parts are special custom order and require long lead times to receive. Replacing problematic transformers prior to failure is cost effective (when compared to emergency replacement), improves the reliability of the system, and provides a methodical process for life renewal of the transformer fleet.

During the past two decades, an increased replacement frequency of power transformers is positively associated with a significant reduction in the number of failures comparing to those in the prior two decades. Proactively replacing units 35 years or older reverses the increasing trend of failure rates against age and lowered the failure rates in the older population to a level associated with random failures.

Given the fact of an aging transformer fleet, more proactive replacements per year will be needed going forward. It is recommended that the annual proactive replacement rate be increased to **six units** per year. Sustaining the proactive replacement rate at 2 units per year would lead to higher failure rates in later years. Six or more proactive replacements per year would yield a flat failure rate across the next 20 years. A rate of six units per year appears to be the point of diminishing return as failure rates would not decline with a proactive replacement rate greater than 6.

Analyses performed on impacts of proactive replacements on fleet average age and future fleet age profile come to the same conclusion: an annual rate of six proactive replacements is optimal. With this higher proactive replacement rate, the in-service transformer failure rate is expected to remain low, close to random failure rates, and thus help to maintain system reliability, employee and public safety, and environmental responsibility. Moreover, an increased flat annual replacement rate may help Con Edison to avoid a "replacement wall" of transformers, resulting in a more predictable budget and manageable outage scheduling.

Transformer Replacement Projects:

Planned Work 2018

Spring

- East 179th St. Substation – Transformer # 5 – Completed Replacement
- West 65th St Substation - Transformer #6 –Completed Replacement
- Elmsford Substation – Transformer #3 –Completed Replacement

Fall

- West 42nd St Substation – Transformer #7 – Begin and Complete Replacement
- East 13th St Substation –Transformers #10 & #11- Begin Replacement
- Gowanus Substation – Transformer #2 – Begin Replacement

Planned Work 2019

Spring

- East 13th St Substation – Transformers #10 & #11 – Complete Replacement
- Gowanus Substation – Transformer #2 – Complete Replacement

Fall

- East 179th St Substation – Transformer #3 –Begin Replacement

Planned Work 2020

Spring

- East 179th St. Substation – Transformer # 3 – Complete Replacement
- Bensonhurst Substation – Transformer #3 – Begin and Complete Replacement
- East River Gen Station – Transformer #7E – Begin and Complete Replacement (Gen Station)
- Cedar St Substation – Transformer #1 – Begin and Complete Replacement

Fall

- Bensonshurst Substation – Transformer #1 – Begin and Complete Replacement
- Corona Substation – Transformer #9 – Begin and Complete Replacement
- Granite Hill Substation – Transformer #3 - Begin and Complete Replacement
- Avenue A Substation – Transformer #1 – Begin Replacement
- East 63rd St Substation – Transformer #2 –Begin Replacement
- East 179th Street – Transformer #2 –Begin Replacement
- Fresh Kills Substation – Transformer #22E – Begin Replacement

Planned Work 2021

Spring

- Avenue A Substation – Transformer #1 – Complete Replacement
- East 63rd St Substation – Transformer #2 – Complete Replacement
- East 179th St Substation – Transformer #2 – Complete Replacement
- Freshkills Substation – Transformer #22E – Complete Replacement

Fall

- Corona Substation – Transformer #7 – Begin and Complete Replacement
- Harrison Substation – Transformer #1 – Begin and Complete Replacement
- Farragut Substation - Reactor #12 – Begin Replacement
- Avenue A Substation – Transformer #2 –Begin Replacement
- East 63rd St Substation – Transformer #6 –Begin Replacement
- Fresh Kills Substation – Transformer #21W (plus a L&P) –Begin Replacement

Planned Work 2022

Spring

- Farragut Substation - Reactor #12 – Complete Replacement
- Avenue A Substation– Transformer #2 – Complete Replacement
- East 63rd St Substation – Transformer #6 – Complete Replacement
- Fresh Kills Substation – Transformer #21W (plus a L&P) – Complete Replacement

Fall

- Corona Substation – Transformer #6 – Begin and Complete Replacement
- Granite Hill Substation – Transformer #2 – Begin and Complete Replacement
- E179th St Substation – Transformer #1 –Retirement of Bank

Planned Work 2023

Spring

- W 42nd St Substation – Transformer #9 – Begin and Complete Replacement
- Parkchester Substation – Transformer 5S – Begin and Complete Replacement
- Corona Substation – Transformer #5 – Begin and Complete Replacement

Fall

- East River Substation – Tie Transformer #1 – Begin and Complete Replacement
- E 13th St Substation –Transformer #17 – Begin Replacement
- Fresh Kills Substation – Transformer #TA-1 – Begin Replacement
- Millwood Substation – Transformer TA-1 – Begin Replacement
- TBD
- TBD

Supplemental Information:

- Alternatives: An alternate strategy would be operating the transformers until failure. This strategy has been rejected because failures can occur at inopportune times, leading to customer outages, as well as result in large repair costs and can have environmental impacts.

- Risk of No Action: Failures can occur at inopportune times, leading to customer outages resulting in large repair costs and can have environmental impacts. The lack of a replacement strategy would lead to a deteriorated transformer fleet that could not maintain system reliability.

- Non-financial Benefits: The project will result in a reliable transformer fleet, leading to reliable service and greater customer satisfaction. Besides reliability benefits, an increased flat annual replacement rate may help Con Edison to avoid a "replacement wall" of transformers, resulting in a more predictable budget and manageable outage scheduling.

- Summary of Financial Benefits (if applicable) and Costs: Benefits include the avoided cost of a possible environmental impact, damage to neighboring equipment or property due to failure. Also a typical replacement would be less costly than a failed unit.

- Technical Evaluation/Analysis: The transformer replacement strategy is condition based. The condition and health of the transformers have been determined using several different assessment tools: one is an on-going research project with EPRI (Electric Power Research Institute) for the Intelligent Fleet Management of our transformers, which has led to the development of a program to evaluate transformers through data-based repair/replace decisions. Additionally, a similar one-time study was completed by ABB, which has worldwide experience with transformer design and manufacturing, along with a health-index ranking tool developed by Equipment and Field

Engineering, a section of Central Engineering. As a result of all of these programs, transformers are evaluated and prioritized for replacement. All retired transformers are inspected and tested to assess the condition of each transformer. An additional program was initiated in 2010 to assess the condition of transformer insulation by testing every transformer for Furans. Analysis of the transformers that have been selected for replacement has confirmed a proper replacement selection.

- Project Relationships (if applicable): Transformer outages are required for replacement. Outages are coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs with the outage or to avoid conflict with other program/ projects.

Basis for Estimate: Near term work derived from engineering estimates based on similar work done in the past. Outer term work based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	5,303	4,916	3,413	8,664		8,519
M&S	5,027	4,161	17,652	17,783		24,075
A/P	3,453	3,051	2,393	8,863		4,349
Other	1,557	312	984	2,180		1,277
Overheads	9,672	8,266	8,526	13,863		11,781
Total	**25,009**	**20,707**	**32,969**	**51,353**	**-**	**50,000**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	7,638	11,366	12,145	9,306	12,262
M&S	19,096	26,567	28,685	21,810	28,357
A/P	6,684	9,945	10,627	8,142	10,730
Other	2,210	2,732	2,958	2,264	3,022
Overheads	12,572	21,110	22,225	16,638	22,269
Total	**48,200**	**71,720**	**76,640**	**58,160**	**76,640**

X	Capital
	O&M

2020 – Electrical Operations

Project/Program Title	Unit Substation Tap Changer Position Indicator System
Project Manager	Maksim Tsarenkov
Hyperion Project Number	PR.2ES6601
Status of Project	In Progress
Estimated Start Date	On-going
Estimated Completion Date	On-going
Work Plan Category	Operationally Required

Work Description:
This program funds the installation of new tap changer position indicators on 4 kV unit substation transformers and their interconnection to our Unit Substation Automation (USA) System to enable remote indication and control.

Voltage regulation of the 4 kV system is provided by tap changers installed in unit substation transformers. In order to use the USA system to facilitate functions such as voltage reduction and to provide the capability of remotely de-loading transformers during a contingency, the use of remote tap changer control with accurate indication is necessary. Approximately 176 tap position indicators were installed previously. We expect to install the remaining 15 stations with tap changer position indicators at a rate of 3 installations per year.

Justification Summary:
In order to effectively implement voltage reduction, which reduces system demand during critical load periods, the 4 kV unit substations must have their tap changers placed in the "remote manual position". This is needed to prevent automatic operation of the tap changers, which would counter the desired voltage reduction. The tap changer position indication system is essential for this function.

In addition, the system allows control center operators to be able to accurately monitor the voltage reduction implementation. The remote indication allows taps to be adjusted while simultaneously monitoring the reduction in loading.

Supplemental Information:

- Alternatives:
  The alternative to this program is to operate the system the same way it has been operating in the past, which is to send personnel to the substation to verify the tap position. This alternative causes a large delay between the time a decision is made to change a tap position and when the tap position is actually changed. Such delays may result in operational issues that damage equipment or interrupt customers.

- Risk of No Action:
  Not installing transformer tap changer position indicators will prevent operators from correctly regulating the voltage on the 4 kV grids. This has the potential to:

- Result in circulating current between stations which may overload equipment and require operational intervention to prevent damage which taxes resources during peak load periods
- Result in customer voltage outside specified limits
- Deny operators the ability to effectively implement voltage reduction during peak loads or contingencies. Voltage reduction is critical for stabilizing the system and preventing further failures during such times

- Non-financial Benefits:
  This project improves system reliability and provides information about the tap position to operators remotely without the slow and expensive process of dispatching operations personnel to verify tap positions. Instead of relying on periodic visits to the station to verify tap changer function, the tap changer position indicator will provide the information remotely via SCADA.

- Summary of Financial Benefits (if applicable) and Costs:
  Reduced operating costs since the correct tap position can be determined without dispatching personnel to the 4 kV Unit Substation.

- Technical Evaluation/Analysis:
  See project justification.

- Project Relationships:
  None

- Basis For Estimate:
  The basis for the funding estimate is the historical unit cost for installing tap changer position indication systems at unit substations.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	7	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	34	-		-
Overheads	-	-	5	-		-
Total	-	-	**22**	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	5	6	6	6	6
M&S	18	19	20	20	20
A/P	1	1	1	1	1
Other	-	1	1	1	1
Overheads	8	9	9	9	9
Total	**33**	**36**	**38**	**38**	**38**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Unit Substation Transformer Temperature Gauges
Project Manager	Maksim Tsarenkov
Hyperion Project Number	PR.8ES5613
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	2022
Work Plan Category	Strategic

Work Description:
This program calls for the replacement of existing temperature gauges with new temperature monitoring units at the company's Unit Substations. The installation of 80 new temperature monitoring units was completed over the last eight years. There are approximately 55 locations left that require temperature monitoring units. The work scope includes equipment installation (cabinets, conduits, cable), programming and testing of temperature monitoring units. The program plans to install 10 new units a year until completion of the program.

Justification Summary:
The existing gauges can provide inaccurate or unreliable temperature readings. Incorrect temperature readings could result in unit substation transformers operating beyond their temperature limits, resulting in loss of transformer life and increased risk of failure. Inaccurate temperature readings may also result in unnecessarily removing a transformer from service due to erroneous high temperature readings, producing unnecessary customer outages. Real-time archived temperature data provided by new monitoring units will allow for the implementation of dynamic ratings, which will help optimize the use of transformer capacity.

Supplemental Information:

- Alternatives:
  The alternative to installing new electronic temperature gauges is to utilize the PT-Load software application which predicts peak transformer temperatures based on transformer data and historical load cycle and is used to determine transformer ratings. The weakness of this approach is that this software produces less accurate ratings than what can be achieved with more accurate data provided by new monitoring units.

- Risk of No Action:
  The inaccurate readings could result in incorrect operator action, increased loss of transformer life, increased risk of failure and sub-optimal use of transformer capacity and consequently, unnecessary transformer replacement.

- Non-financial Benefits:
  The electronic temperature monitoring units provide a number of beneficial features such as SCADA connectivity, which will provide remote temperature data for real time operations and

planning. In addition the new units will provide local indication and storage of maximum temperature reached, which will allow field crews to utilize temperature data for operation. The implementation of this program will result in more accurate operation of the 4 kV distribution systems, fewer customer outages and will provide dynamic rating capability which will allow optimal use of transformer capacity. The installation cost of electronic temperature monitors is estimated at approximately $7,000 each.

- Summary of Financial Benefits (if applicable) and Costs:

- Technical Evaluation/Analysis: Real-time archived temperature data provided by new monitoring units will allow for the implementation of dynamic ratings, which will help optimize the use of transformer capacity.

- Project Relationships (if applicable): None

- Basis for Estimate: Historical unit costs.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M Only)	Forecast 2018
Labor	2	0.8	18	12		-
M&S	2	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	2	(1.6)	10	7		-
Total	**6**	**0.8**	**28**	**19**		**-**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	46	60	68	68	68
M&S	8	6	-	-	-
A/P	-	-	-	-	-
Other	1	1	-	-	-
Overheads	22	28	32	32	31
Total	**76**	**95**	**100**	**100**	**99**

X	Capital
	O&M

2020 – Electric Operations

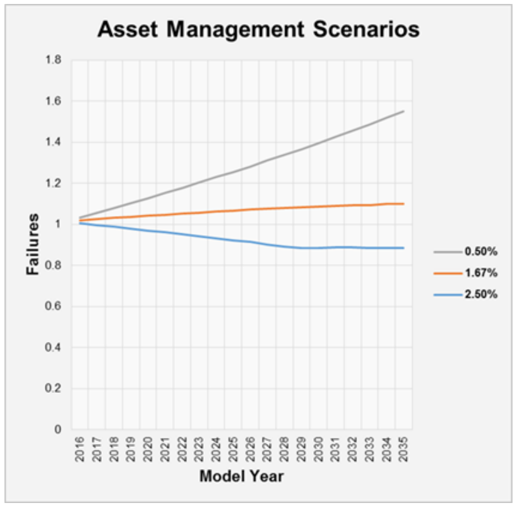
Project/Program Title	Unit Substation Transformer Replacement program
Project Manager	Maksim Tsarenkov
Hyperion Project Number	PR.0ES9807
Status of Project	In Progress
Estimated Start Date	2019
Estimated Completion Date	On-going
Work Plan Category	Strategic

Work Description:
Replace the existing Unit Substation Transformers, a total of four (4) per year with new 10,500 KVA transformers.

Justification Summary:
There are 239 4kV Unit Substation Transformers and 45 4kV High Tension Vaults in Con Edison distribution system (total of 284 4kV transformers). They carry about 10% of the total load and play an important role in overall system reliability. Over the past 20 years, a third of these transformers were replaced with new larger banks to compensate for growing load under the Load Relief Program. However, in the past six (7) years, there have been no USS transformer replacements due to the forecast load growth in the Load Relief Program. The average age of USS transformers is now 30 years old, with approximately 100 of them over the age of 45, while the oldest units are currently 63 years old. By the year 2019, the oldest units will be 64 years of age.

The Company began utilizing a model/matrix in 2016 to calculate a health index for its USS transformers. Based upon that model/matrix, units that have a score outside of the target are recommended for replacement. A USS transformer with a health index score above the goal has an increased risk of an in-service failure. The model/matrix utilizes the following factors in its health index calculation; DGOA (Dissolved Gas in Oil Analysis), Furan test results, transformer loading, apparent corrosion, oil leaks, LTC (Load Tap Changer) functionality, environmental impact, proximity to public, and age. The company plans to replace all USS transformers that have a score above the goal.

Asset Management has completed the asset class model for unit substation transformers. Based on that model, in order to maintain the current failure rate, 4 transformers need to be replaced every year. Replacement will be predicted by the asset health index.



Projection based on life-cycle model with three types of transformer, with oldest/worst transformers failing at .4% (1/239) per year, replacing with new transformers failing at 0.16% initially, and with 2.5% annual growth rate of failure rate, based on ConEdison experience in the last 15 years. Percentage replacements are as a percent of all 239 transformers, i.e., 1.67% = 4 transformers per year, including the one that might have failed.

Based on wide utility industry experience and analysis of transformer paper decomposition (ASTM D5837) there is a strong correlation between transformer's service age, its insulating paper decomposition, and its failure rate. Con Edison USS failure rate is currently around 1 transformer per year; however, if no replacements are made, as the fleet ages, the failure rate will increase. Failed transformers are invariably more expensive to replace under emergency condition, than planned replacement. Predicting far in advance exactly which transformer will fail and when is currently impossible. Yet it is understood that transformers with deteriorated insulating medium will fail with much greater probability than the same transformer with healthy insulation.

It is proposed to replace certain transformers based on a USS Transformer rating system based on parameters such as DGOA (Dissolved Gas in Oil Analysis), Furan test results, transformer loading, apparent corrosion, oil leaks, LTC (Load Tap Changer) functionality, environmental impact, proximity to public, age. In order to estimate the number of transformers to be replaced every year, the following method is used: Considering furanic compounds (paper decomposition) per ASTM D5837 as the main parameter for the cut off age, it was found that the average transformer in the 4kV grid will reach the end of its operating life at approximately 70 years. This cut-off age shall not be treated as an absolute end of life, since all transformers age at different rates, but is used only as a guide for calculating the number of transformers needed to be replaced every year in order to avoid having too many of them past that age.

Below is the list of Unit Substation Transformers that are currently proposed for replacement in 2019-2021:

Year Replace	Unit Substation	Manufacturer	S/N	KVA	Year Built
2019	Tompkinsville	PENN	C02991-5-4	7000	1968
	Heathcote 23	MOLONEY	919545	6250	1957
	Wolf's Lane 105	MOLONEY	916877	5000	1956
	Hastings 9	W	5067728	6250	1953
2020	Silver Lake # 1	PENN	37664-3	6250	1958
	Canterbury	PENN	C02593-5-1	7000	1967
	Ferncliff	MOLONEY	916876	6250	1956

	Primrose	GE	C859854B	7000	1964
2021	Ralph Ave 1	W	6990644	6250	1961
	Lawrence Park	GE	C160393	6250	1955
	Green Knolls	GE	C859009	6250	1959
	Floral Park 2	PENN	C02990-5-1	7000	1968
2022	Mount Hope	MOLONEY	919547	6250	1957
	Sherwood Park	W	6531048	6250	1955
	McLean 1	MOLONEY	1880020	6250	1960
	Valley Place	MOLONEY	1880023	6250	1960

Supplemental Information:

- Alternatives:
  The alternative is to increase the number of spare transformers. This however, carries extra cost of replacing the transformers under emergency and increased storage charges. In addition, a failed transformer creates a potential for public safety, equipment damage, and create an environmental disaster.

- Risk of No Action:
  Aging of equipment will eventually cause failures that may carry high environmental risks and jeopardize 4kV system reliability. The failure curve indicates that if left unaddressed the system will see more failures than man-power and budget can accommodate. System stability concerns may prohibit us from replacing much larger number of transformers at once.

- Non-financial Benefits:
  - Reliability.
  - Increase in available capacity for future expansion.
  - Reduced environmental impact, including total absence of PCBs in new transformers and reduction in the number of oil-filled compartments due-to new design spec.

- Summary of Financial Benefits (if applicable) and Costs:
  - Reduction of LTC maintenance cost for life of the transformer – $50,000 per transformer.
  - Reduction in number of transformers replaced under emergency condition – over $1.3M
  - Reduction of some future Load Relief related installations - over $1.3M

- Technical Evaluation/Analysis:
  Presented in Justification Summary.

- Project Relationships (if applicable):
  Presented in Justification Summary.

- Basis for Estimate:
  Past and present costs of installations of 10,500 kVA USS transformers, escalation and contingency included.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	198	405		543
M&S	-	-	228	1,123		3,357
A/P	-	-	19	100		106
Other	-	-	37	78		163
Overheads	-	-	207	545		1,234
Total	-	-	**689**	**2,251**		**5,403**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	570	2,450	1,400	1,400	1,400
M&S	1,903	2,583	1,602	1,602	1,602
A/P	-	-	-	-	-
Other	193	311	227	231	233
Overheads	297	1,186	673	669	668
Total	**2,964**	**6,530**	**3,902**	**3,902**	**3,902**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Transformer Vault and Structures Modernization
Project Manager	Jane Shin
Hyperion Project Number	PR.2ED1001, PR.2ED3011, PR.2ED4001, PR.2ED2011, PR.2ED5001
Status of Project	In Progress
Estimated Start Date	On-going
Estimated Completion Date	On-going
Work Plan Category	Operationally Required

Work Description:
This program provides funding for proactive repair of structural deficiencies in deteriorated transformer vaults, manholes and service boxes. If unrepaired, structural deficiencies in deteriorated vaults present a risk of collapse that can be a hazard to the public and can compromise system reliability by causing damage to electric infrastructure. Program funding has been increased in order to reduce the number of on-hand structures identified with deficiencies.

The program objectives are to identify and prioritize structures with defects and proactively repair those defects. Proactive repair of structures is significantly less costly than repair after collapse.

Structural deficiencies found include settlement, cracked concrete, spalled concrete, collapsed walls, collapsed ceilings, corroded steel beams and columns, and corroded rebar. These deficiencies involve deteriorated roofs, walls, and floors. Repairs require significant rebuild involving steel, concrete, and masonry components along with the associated inspection, excavation, waterproofing, and backfill/restoration tasks.

It is anticipated that in 2018, 80 structures will be identified, and those 80 identified structures will be replaced. This program addresses any civil work required to fix these structures that is ruled capital.

Justification Summary:
Severe structural deficiencies must be addressed due to the following:

- Public safety risks related to slips, trips or falls, sunken roofs, or structural collapses
- Employee injury risk due to falling concrete or structural collapses
- Reliability risk due to damaged transformers and cable from falling debris
- Fines from the City of New York due to settled structures and cracked concrete
- Impact to customers due to water intrusion at customer service entrances

At locations where temporary steel plates and barricades are installed, these plates present trip/fall hazards along with the potential for city fines. In addition, steel plates prevent air-flow to structures reducing the capability of transformers may affect system performance during summer peak periods.
Transformer vault defects and repairs are prioritized based on electrical deficiencies and other external factors, such as:

- Customer complaints

- Mitigation of potential lawsuits
- Coordination with other company priority programs

Structural repairs incorporate the latest engineered materials including epoxy-coated rebar, concrete roof waterproof membranes, embedded steel beams, anti-corrosive galvanizing paint over beams, and welds and enhanced cathodic protection.

Supplemental Information:

- Alternatives:
  The alternative to performing structural repairs is to install temporary shoring within structures to address imminent collapse. However, since degradation is progressive, repairs must eventually be completed. The Company devotes significant effort to evaluating and prioritizing structural deficiencies in order to reduce costs. Deficiencies initially identified during inspections by field crews are further evaluated by engineering personnel to ensure that they are properly categorized and prioritized. The structural deficiencies deemed significant after evaluation must be addressed as they pose safety risks to the public and Company personnel as well as to the equipment.

- Risk of No Action:
  Failure to address deteriorated structures will risk the safety of the public and Con Edison employees, impact system reliability, and expose the Company to fines from New York City.

- Non-Financial Benefits:
  The non-financial benefits of this program are:
  - Improved public and employee safety
  - Improved system reliability
  - Improved relationships with external stakeholders

- Summary of Financial Benefits (if applicable) and Costs:
  The financial benefits of this program are:
  - Extending the useful life of Company assets and thereby reducing costs
  - Reducing the costs associated with fines from NYC due to structural defects
  - Reducing the number of environmental events related to oil release from transformers

- Technical Evaluation/Analysis:
  Please see the appendix for detailed case studies of needed repairs.

- Project Relationships (if applicable)
  - Underground Secondary Reliability
  - Banks Off

- Basis for Estimate:
  Cost estimates used for this project are based on the following:
  - Active vault repair contract
  - Active area trenching contract
  - Repairs completed by Subsurface Construction

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,455	2,026	2,275	3,416		2,343
M&S	682	426	890	2,210		1,371
A/P	3,145	2,441	2,370	6,252		4,615
Other	(110)	42	636	41		36
Overheads	3,333	3,898	3,843	6,442		4,734
Total	**8,505**	**8,833**	**10,014**	**18,361**		**13,099**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	2,335	3,005	3,005	3,005	3,005
M&S	1,131	1,456	1,456	1,456	1,456
A/P	3,817	4,913	4,913	4,913	4,913
Other	131	168	168	168	168
Overheads	4,512	5,807	5,807	5,807	5,807
Total	**11,927**	**15,350**	**15,350**	**15,350**	**15,350**

APPENDIX

This appendix provides pictures of deteriorated structures.

The following are photos showing the condition of some actual structures:

Collapsed Roof

Corroded steel beam flaking at beam seat

Delaminated concrete with exposed rebar – roof replacement is required (cannot be repaired)

X	Capital
	O&M

2019 – Electric / Substation Operations

Project/Program Title	Transmission Station Metering & SCADA Upgrades.
Project Manager	James Neilis
Hyperion Project Number	PR.21510977
Status of Project	Planning
Estimated Start Date	January 2016
Estimated Completion Date	Ongoing
Work Plan Category	Regulatory Mandated

Work Description:
In recent years, the number of outstanding deficiencies and faulty equipment on the Company's systems for the Bulk Electrical System (BES) has increased. A system wide survey will be performed to verify the existing reported metering deficiencies, and determine possible additional deficiencies, that may impact the reliable operation of the Company's electric system, as well as to identify conditions that do not comply with company specifications and/or regulatory requirements. The results of that survey will be used to prioritize and implement any necessary remediation measures. Equipment to be addressed includes Coupling Capacitor Potential Devices (CCPDs), Potential Transformers (PTs), Current Transformers (CTs), Bushing Potential Devices (BPDs), transducers, and associated wiring.

These existing deficiencies will be classified in different groups depending on the cause of the problem and the approach to be taken for their resolution. To date, we have identified several program categories, including, but not limited to:

- Unavailability of devices: This category will include all metering devices, instrument transformers and wiring that are malfunctioning, obsolete, or had been previously removed or retired in place. In this case, the system will be re-engineered to be functional and new equipment will be installed.
- Lack of accuracy: Aging and underrated equipment will fall in this category. These devices will be upgraded to at least meet the minimal requirements set by the regulatory bodies. New settings and configurations will be reissued when needed.
- New metering points: Includes operational performance metering that does not currently exist on the Company's system. Work in this category includes design and implementation of new metering infrastructure.

Stations currently identified for upgrade include, E179th Street, Farragut, Sherman Creek, Sprainbrook, Goethals and Dunwoodie 345kV/South/North. Additional substations will be evaluated and are expected to be recommended for replacement under this program.

Justification Summary:
The State Estimator (SE) is a program that uses available real-time telemetered analog measurements (e.g., MW, MVAR, AMPS, KV) and digital measurements (e.g., breaker status, switch status) to determine or estimate a consistent set of voltages (magnitude and phase angle) at each node where metering is available. Using the set of estimates (solution), the SE calculates other quantities (e.g., branch flows, loads, tap information) to compare their corresponding measurements and provides them to the contingency analysis (CA) program to use in running what-if scenarios and providing the operators with alerts and valuable data. The accuracy of the SE is proportional to the measurement accuracy and redundancy; the more accurate the telemetered data and the more sources available for a specific measurement, the more accurate the solution.

The accuracy and availability of metering, SE, and CA systems is also tied into and governed by various regulatory requirements. In addition, The North American Electric Reliability Corporation (NERC) Event Analysis Program (EAP) requires that Loss of the SE or contingency analysis capability lasting 30 continuous minutes or longer be reported. Also, once the Company registers as Transmission Operator (TOP) starting July 1 2016, NERC EOP-004 requires the same but with an additional form and tighter timeframe and NERC standard TOP-006-2 on Monitoring System Conditions requires the "use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations" (requirement 6). Furthermore, TOP-010, a new NERC standard being developed, will establish certain quality guidelines for real-time monitoring and analysis capability available to BES operators. The current draft requires operators to have visibility of data quality discrepancies (e.g. data outside of a prescribed data range or not updated within a predetermined time period).

Undoubtedly, lack of accurate and reliable telemetered data and the loss of SE or CA due to lack of accurate and reliable telemetered data would result in regulatory liability, reputational damage and decreases in reliability.

Supplemental Information:

- Alternatives: Repair existing metering equipment and restore to original configuration. This alternative would restore non-functioning metering points to the SE, however this alternative may not improve the accuracy of the restored metering data points because of the low accuracy class of the older type PTs, CCPDs and CTs. Older transducer models are obsolete and no longer manufactured. Additionally, legacy circuit breaker Bushing Potential Devices (BPDs) that provide voltage to metering systems, are often unreliable and obsolete. For these reasons the repair alternative is not recommended as a long term system-wide solution.

- Risk of No Action: No action will leave the system in a heightened state of risk and will place Con Edison at risk of regulatory liability after additional standards become applicable to the Company. There is also diminished operational capability that may impact transmission and distribution system operability and reliability.

- Non-financial Benefits: Non-financial benefits include increasing operational visibility and the operator's ability to effectively control the system. Additional benefits include the possible deferment of projects intended to increase power system capacity.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: Substation surveys will be performed starting with substations on the Company's Bulk Electric System or substations with a history of metering issues reported in Maximo, to identify issues and deficiencies as discussed in the work description section above.

- Project Relationships (if applicable): N/A

- Basis for Estimate: Engineering Estimate

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	502		375
M&S	-	-	115	714		15
A/P	-	-	-	377		1
Other	-	-	26	13		11
Overheads	-	-	-	692		407
Total	**-**	**-**	**141**	**2,298**		**809**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	230	1,003	1,036	1,012	1,012
M&S	128	552	552	552	552
A/P	61	276	246	291	276
Other	35	153	153	154	158
Overheads	221	1,082	1,079	1,057	1,068
Total	**675**	**3,066**	**3,066**	**3,066**	**3,066**

X	Capital
	O&M

2019– Central Operations/Substation Operations

Project/Program Title	U-Type Bushing Replacement Program.
Project Manager	Steven Bryan.
Hyperion Project Number	20704842.
Status of Project	Ongoing
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
A bushing is a device that brings out the transformer internal winding leads through an insulating tube for connection to the power system. Utility industry experts have identified transformer bushings that have design and manufacturing problems. The identified bushings are General Electric Type U, Haefely Trench Type COTA and OTAA bushings and F&G (Felten & Guilleaume)/HSP Type OTF bushings. Failure of the bushings can lead to transformer failure, decreasing system reliability and availability of transformers on the transmission and sub-transmission systems.

Approximately thirty (30) 345 kV bushings, two-hundred and forty (240) 138 kV bushings, twenty-five (25) 69 kV bushings, and ten (10) 23 kV bushings have been identified for replacement and upgrade.

It is recommended that identified bushings be replaced and upgraded based on failure probability and system impact. The recommended priority is:

1. 138 kV and 345 kV shunt reactors
2. 345 kV transmission autotransformers
3. All phase angle regulators (PARs)
4. Other 138 kV and 345 kV auto-transformers
5. Two bank area substation transformers
6. Other area substation transformers

Justification Summary:
A major component of a power transformer is a bushing. General Electric Co. (GE) was a major supplier of bushings for all transformer manufacturers until the late 1980s. GE manufactured bushings with ratings from 15 kV through 800 kV and has served over 60% of the US market. One of the many types of bushings that GE supplied was the Type U bushing, a condenser-type design. The condenser-type design utilized a metal core tube with insulating paper and an electrically conductive foil or semi-conductive electrode wound around the core. The Type U design used alternate layers of plain Kraft paper and Kraft paper with conductive ink printed in a herring-bone pattern on the surface. In the late 1970s, users reported increases in the power factor of Type U bushings.

Teardown of failed and high power factor bushings revealed the following problems:

1. Heavy loading of some transformers (e.g., generator step-up transformers and shunt reactors), generated a higher internal temperature than the temperature expected from conductor-generated heat. This higher temperature resulted in increased pressure in the gas space above the oil, leading some of the gas to become dissolved in the oil. Rapid temperature cycling

resulted in gas bubble generation and a reduction of dielectric strength Insulation system degradation resulted in an increased power factor.

2. Over time, the conductive ink transferred from the printed-paper layers to the plain kraft paper layers. This bleeding of the conductive ink resulted in an increased power factor.

3. The terminal connection on the top of the bushing used a "flex-seal" system composed of a gasket, a seal nut, and a spring. If the cover bolts became loose over time, hot spots developed that compromised the gasket seal. Water would enter the bushing through the compromised gasket seal.

Type COTA bushings from Haefely Trench experienced unexpected failures in the middle of the last decade. Haefely Trench started manufacturing the Type COTA bushings in 1994. The Type COTA is also a condenser-type design. The failures occurred around the flange section of the bushing. The Type COTA bushing is shorter than bushings of the same rating manufactured by other manufacturers, which made it a good universal replacement. Because of the shorter dimension, the design must control the maximum and average voltage stresses in the Kraft paper insulation system.

Con Edison and other users started measuring the power factor of the Type COTA bushings and reported increased power factor measurements, which indicates degraded insulation. No definitive root cause was found for the bushing failures.

In addition, Type OTF bushings from Felten & Guilleaume (F&G)/HSP have experienced unexpected failures over the last two decades. The Type OTF bushing is also an oil-impregnated paper condenser-type design with a porcelain upper housing and an epoxy resin lower part. Many of these failures were catastrophic resulting in the explosion of the porcelain housing. Additional deteriorated bushings have been removed from service due to bushing electrical test results and dissolved gas-in-oil analysis that indicates a degradation of the bushing’s condition and concern over its reliable performance. No one definitive root cause was found for the bushing failures.

Bushings are subjected to high dielectric, thermal, and mechanical stresses, which makes them a critical component of a transformer. It has been well documented that the physical damage a failed bushing causes can lead to a damaged power transformer.

Upgrading bushings to the ABB design will result in a reliable transmission and sub-transmission system, a reliable and available transformer, and minimal transformer failures from bushing failures.

Supplemental Information:

- Alternatives: Perform routine power factor testing on existing bushings that have a higher potential of failure. Bushings and/or a transformer could fail between periodic testing during the summer period, negatively impacting the reliability of the transmission system. In addition, this would also result in numerous additional outages for testing. Therefore, this alternative is not acceptable.

- Risk of No Action: Waiting for bushings to fail and then replacing them can cause transformer failure. This alternative is not acceptable since failure of a bushing and/or a transformer during the summer period will negatively impact the reliability of the transmission system. In addition, replacing a transformer can cost $15M to $40 M, which is significantly more than the cost of replacing the bushings.

- Non-financial Benefits: Upgrading bushings will result in a reliable transmission and sub-transmission system and minimize transformer failures from bushing failures.
- Summary of Financial Benefits (if applicable) and Costs: Bushing failures have the potential to be catastrophic resulting in costly damages to transformers and lengthy outages on the system that could impact customers.

- Technical Evaluation/Analysis: Utility industry experience has shown that General Electric Type U, Haefely Trench Type COTA and F&G/HSP type OTF bushings have design and manufacturing problems that can lead to the catastrophic failure of the bushing. Industry bushing guides, such as IEEE and Doble Engineering, recommend that any GE Type U bushing having a C1 power factor which has increased to an absolute value of 1% or higher, or which exhibits a sudden, significant increase in power factor, though not yet exceeding the 1% maximum, should be considered in questionable condition. Similarly, investigation and evaluation of Trench COTA bushing failures indicate that they may be experiencing accelerated aging which can be assessed through the periodic measurement of bushing power factor and capacitance and compared against threshold values of 150% of nameplate power factor and an increase of more than 2.5% than the C1 capacitance value. Once the increase in the power factor is exhibited, it continues to increase rapidly.

  Experience with our installed equipment has included the catastrophic failures of GE Type U bushings on Queensbridge Transformer TR3, Farragut Reactor R12, Corona Transformer TR8 and W50 St. Transformer TR2. In addition, measurements of bushing power factors on W50 St. Transformers TR1, TR3 and TR4, Fresh Kills Transformer TB1 and Leonard Street Transformer TR9 have picked up degraded bushings prior to their catastrophic failure. Our operating experience on Haefely Trench Type COTA bushings has included the catastrophic failure of a bushing in Corona Transformer TR1. Subsequent testing of the installed sister bushings in this transformer confirmed elevated bushing power factor and capacitance measurements. Experience with our installed equipment with F&G/HSP type OTF bushings has included the catastrophic bushing failures of PARs 3500 and 4500 at Ramapo Substation. The most recent failure of the F&G bushing at Ramapo that failed catastrophically resulted in the total failure of the phase angle regulator 3500.

- Project Relationships (if applicable): Bushing replacements may be scheduled in conjunction with Tap Changer inspections where the increased outage duration does not impact the system.

- Basis for Estimate: Near term work based on Engineering estimates, which are based on similar work done in the past. Outer term work based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature. Looking to address all trench bushings by the end of 2019. This will require an increase in 2019 capital spending in this program.

Total Funding Level ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,846	274	552	698		1,558
M&S	81	23	197	200		120
A/P	970	161	111	350		168
Other	194	11	61	139		451
Overheads	2,216	355	487	903		1,510
Total	**5,307**	**825**	**1,408**	**2,290**		**3,808**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Budget 2021	Budget 2022	Budget 2023
Labor	3,427	918	1,004	1,888	1,888
M&S	269	76	83	156	142
A/P	1,469	410	452	849	849
Other	79	23	34	86	83
Overheads	2,915	867	937	1,741	1,758
Total	**8,159**	**2,294**	**2,510**	**4,720**	**4,720**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Underground Secondary Reliability
Project Manager	Stan Lewis/Mark Riddle
Hyperion Project Number	PR.4ED4231, PR.5ED0101, PR.4ED1431, PR.4ED3351, PR.4ED7811, PR.4ED2101
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
The Underground Secondary Reliability Program is an existing and ongoing program that replaces and upgrades underground secondary equipment and facilities. This program reinforces secondary network infrastructure by replacing and upgrading underground structures, conduits, transformers and cable. The Underground Secondary Reliability Program addresses both system design and public safety through different subprograms.

System Design focuses on work associated with maintaining the highly reliable network design basis. System design considerations include contingency, reinforcement, and proper equipment operation. Program units and schedule for System Design are shown in the table below.

Underground Secondary Reliability – System Design					
Type (Units)	**2019**	**2020**	**2021**	**2022**	**2023**
UG Conduit (Trench Feet)	7,900	8,500	9,000	9,500	9,500
UG Manhole Vault (Number)	30	32	35	38	38
UG Secondary Main Cable (Sections)	500	550	600	650	650
UG Service Box (Number)	100	110	120	130	130
UG Service Cable (Sections)	115	120	125	130	130
UG Service Conduit (Trench Feet)	1,500	1,800	2,000	2,200	2,200

Secondary Rebuild proactively replaces secondary equipment and mains in order to reduce the number of energized objects (street lights, manhole covers, etc.), outages, and manhole events. The program's goal is to reduce the present five-year manhole events average by over 5% starting in 2022. To accomplish this goal, this program targets structures that have combinations of aluminum and 4/0 mains, experienced an Underground Secondary Event (UGSE) – smoke, fire or explosion, and use of wood or wood-fiber ducts. Replacements are separated into three groups based on the combination of these attributes:

1. Tier 1 replacements include structures with recent UGSEs, aluminum , 4/0 cable and wood(fiber) conduit
2. Tier 2 replacements include strictures with recent UGSEs , aluminum and 4/0 cable, but no wood(fiber) conduit
3. Tier 3 replacements include structures without recent UGSEs but that do contain aluminum or 4/0 cable and wood(fiber) conduits

Program units and schedule for Secondary Rebuild are shown in the table below.

	Underground Secondary Reliability – Secondary Rebuild				
Type (Units)	**2019**	**2020**	**2021**	**2022**	**2023**
UG Conduit (Trench Feet)	18,000	18,000	18,000	18,000	18,000
UG Secondary Main Cable (Sections)	1200	1200	1200	1200	1200

Secondary Service Replacement program focuses on the replacement of service cables selected analytically based on performance or by inspection finding.

Program units and schedule for Secondary Service Replacement are shown in the table below.

Underground Secondary Reliability – Secondary Services					
Type (Units)	**2019**	**2020**	**2021**	**2022**	**2023**
UG Service Conduit (Trench Feet)	10,000	10,000	10,000	10,000	10,000
UG Service Cable (Sections)	1,000	1,000	1,000	1,000	1,000

The Secondary Rebuild Program will also include crab and main replacement work associated with hotspot findings from the enhanced inspection program.

Emergent Reliability includes work associated with new initiatives including enhanced inspection for non-visible defects and changes to the system design basis such as half element limiters and structure fill.

Enhanced Inspection utilizes Infrared camera technology and current measurements to detect visibly hidden defects and prioritize their correction. Correction can range from the remaking of a single connection to the full replacement of cable sections and crabs depending on the condition of the cable and crabs in the structure.

Half-element limiter adds limiters to locations in the network that will isolate the smallest possible section of faulted equipment in the shortest time. These additional limiters will help minimize collateral damages and number of UGSE.

Structure Fill focuses on the principle that for combustible driven manhole events the available volume of gas in a structure is directly proportional to the energy of explosion. This program will reduce structure volume by inserting pillow- sized containers with non-combustible material into underground structures, therefore reducing any event energy.

Program units and schedule for Emergent Reliability work are shown in the table below.

Underground Secondary Reliability – Emergent					
Type (Units)	**2019**	**2020**	**2021**	**2022**	**2023**
Half-Limiters crabs (each)	100	150	200	200	200
Non-visual Detection -VDC(Structures)					
▪ Cameras	125	30	30	30	30
▪ Cut & Rack	20	20	20	20	20
▪ UG Secondary main Cable (Sections)	50	50	50	50	50
Structure Fills(Structures)	5000	5000	5000	5000	5000

Program units and schedule for Underground Secondary Reliability in total are shown in the table below.

Underground Secondary Reliability – Program Totals					
Replacements (Units)	**2019**	**2020**	**2021**	**2022**	**2023**
UG Mains Conduit (Trench Feet)	25,900	26,500	27,000	27,500	27,500
UG Manhole Vault (Number)	30	32	35	38	38
UG Secondary Main Cable (Sections)	1,750	1,800	1,850	1,900	1,900
UG Service Box (Number)	100	110	120	130	130
UG Service Cable (Sections)	1,115	1,120	1,125	1,130	1,130
UG Service Conduit (Trench Feet)	11,500	11,550	11,600	11,650	11,650
Half Limiters Crabs	100	150	200	200	200
Structure Fill	5,000	5,000	5,000	5,000	5,000
Cut & Rack(structures)	20	20	20	20	20
IR Cameras	125	30	30	30	30

Justification Summary:
Damage to the secondary system is generally harder to identify compared to the primary system due to the redundancy of the secondary grid, magnitude of assets, and limited presence of remote monitoring equipment beyond the network transformer. As a result, many conditions are not found until they result in a customer outage, manhole event (smoke, fire, and explosion) or stray voltage condition. Moreover, the failure of a secondary cable may also result in collateral damage immediately by way of fire or explosion and in the future from the stresses created by short circuit currents. Since these conditions can lead to hazards to the public or prolonged outages, maintaining the safety and reliability of the secondary grid is a priority. Networks and structures will be targeted for proactive secondary mains and services replacement based, in part, on performance, build, and defect conditions. Additional treatments, such as limiters and structure fill will also be utilized to minimize risk.

In an effort to manage assets and failure risk proactively, the Secondary Rebuild and Service Replacement programs seek to make cable and connection replacements before a failure occur.
Analysis of the construction of structures that have experienced events involving property damage or injury shows approximately that 4/0 cable was present in 50% of cases, wood or wood-fiber duct in 30%

and aluminum cable in 17% of events. The Secondary Rebuild Program will thus focus on structures having the greatest combinations of these attributes.

In an average year, more than 1,800 utility side sources of contact voltage are discovered and mitigated. These sources are discovered through existing programs that scan for contact voltages on street level publically accessible metallic objects and through customer call-in reports. From these detections, compromised underground services account for approximately 50% of the sources to energized objects. The goal of Services Replacement program is to identify and replace these compromised services before they present a danger to the public or employees by energizing street level metallic objects or metallic objects within the customer premises.

Supplemental Information:

- Alternatives:
  This is the only program that specifically prioritizes secondary grid reinforcement and replacement. An alternative to this program would be to coordinate secondary grid reinforcement and replacement with other work in any given structure. While doing so might slightly reduce the rate of UGSEs, it would not be statistically significant.

  Assets can continue to be run to failure with risk control through other public safety programs such as stray and contact voltage testing, inspection and vented covers. While all of these contribute to risk control, there are still thousands of manhole events each year.

  Risk of No Action:
  Any asset that is run to failure could result in personal injury, property damage or loss of reliability. Failure to maintain minimum thresholds of performance could result in the company having to pay fines.

- Non-financial Benefits:
  The primary non-financial benefit of this program is an improvement to public safety. With full program support, by 2022 the five-year manhole event average should be reduced by at least 5% or approximately 100 events per year, of which 4-8 would be significant manhole fires or explosions involving property damage or injury. During the first five years of the program, Tiers 1 and 2 would receive cable and connection replacements. All structures would receive a treatment including bagged fill, monitoring and/or vented cover.

  Additionally, this program will contribute to a reduction in emergency response time, particularly during peak event periods (such as storms), since fewer emergency events will occur. It will also contribute to a reduction in troubleshooting time since defective equipment will be replaced before creating an energized object which can be time consuming to diagnose.

  Finally, customer satisfaction will be improved by the increased reliability.

- Summary of Financial Benefits (if applicable) and Costs:
  Every event avoided represents an emergency response not performed, an open main not created, and potential property damage and/or injury avoided. Thus, for the prospective 100 events avoided, an operations cost savings of $0.5M per year is expected. Energized objects take an average of eight man-hours to investigate and make safe. An estimated reduction of 100 energized objects per year would equate to approximately 800 man-hours or $80,000 saved in labor costs.

Additionally, the increased reliability and inspection rate that will result from this program will lower the Company's exposure to regulatory fines.

- Technical Evaluation/Analysis:
  Compromised secondary main cable failure has the potential to inflict serious injury to employees and members of the public as well as to cause damage to property. Events of this nature have historically been viewed as predominately random. After analysis, these drivers are common to the greater percentage of these events. Preemptive action on this asset group will significantly reduce their probability to trigger a future occurrence.
  Our findings reveal that structures with a pre-event build of aluminum and/or 4/0 type cables experience UGSE's at a rate of up to four times that of 500 Circular Mils (MCM) cable, when normalized to their system population. Additional observations have revealed:
  1. In instances where the aluminum and 4/0 traverse a wood and/or wood-fiber conduit, the public safety impact is greater as Carbon Monoxide gases are produced in greater quantities as both the cable and the conduit are consumables in the fire. The additional consumable also protracts the duration of the event.
  2. It has been observed that approximately 20% of structures with an event in any given year will experience another event within the following five years. This rate of reoccurrence likely reflects that the stresses from one cable's failure can cause collateral damage to adjoining cables, leading to a repeat event.

  Compromised secondary service cable (e.g. supplying street lights & residences) accounts for approximately 50% of the energized object sources. The potential to inflict both serious injury to employees and members of the public is a real possibility. Historically, events of this nature have been viewed as predominately random. However, after a similar analysis, drivers for these events have also been determined.

  For example, analysis has revealed that the rate of energized equipment (ENE) generation is higher in areas with lead mains and services. The rate of ENEs can be up to four times that of other mains and services cable when normalized to system populations. In winter periods, lead insulated cables can account for almost 45% of the publically accessible electric shocks, even though the lead cable population is less than 15% on the system.

  The half-limiter program will install limiters with approximately half the current pickup and clearing time of existing limiters. These crabs will be installed starting with midblock locations of appropriate loads. These limiters will a) increase sectionalizing, thus reducing collateral damage and potential outage, and b) improve clearing times thus, reducing stresses on the cables.

  The structure fill program focuses on combustion driven events and removing the requirements for combustion – fuel, air, and ignition. Pillow size containers will be installed that displace combustible gas and air from the structure as well as isolating any possible ignition source. Moreover, using Brode's equation, any combustion event that were to occur would be of lesser energy in proportion to the volume of space taken up by the fill.

- Project Relationships (if applicable):
  - Secondary Inspection Program (PSC Mandated)
  - Eight Year Inspection Program (O&M)
  - PILC Cable Removal Program

- Basis for Estimate:
  The estimate was based on the capital costs associated with replacing compromised equipment. Unit costs of replacing sections of conduit and cable and retiring cable in place are known from historical data.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	6,587	5,357	6,210	10,616		8,759
M&S	2,797	2,680	4,144	5,203		3,259
A/P	7,414	3,459	3,198	7,935		8,060
Other	14,746	3,517	1,464	1,012		2,681
Overheads	10,759	8,477	7,695	12,580		10,765
Total	**42,303**	**23,490**	**22,711**	**37,346**		**33,525**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	5,485	6,320	6,474	6,152	6,305
M&S	5,064	6,763	8,861	7,324	8,118
A/P	6,637	12,596	17,299	18,790	18,145
Other	4,708	5,664	6,474	6,115	5,885
Overheads	11,246	13,658	15,893	16,619	16,546
Total	**33,140**	**45,000**	**55,000**	**55,000**	**55,000**

X	Capital
	O&M

2020 – Electrical Operations

Project/Program Title	Unit Substation Pressure and Oil Sensors
Project Manager	Felipe Valverde
Hyperion Project Number	PR.23492822
Status of Project	In Progress
Estimated Start Date	2019
Estimated Completion Date	2025
Work Plan Category	Strategic

Work Description:
This program funds the SCADA connection to XA21 of Nitrogen Pressure and Oil Level sensors on Con Edison's Unit Substation Transformers. There are 239 transformers with about 1,000 oil-filled compartments that have Oil Level and Nitrogen Pressure sensors that currently do not have any remote monitoring. It is proposed to install the necessary SCADA equipment to bring the monitoring to the operators' displays.

Justification Summary:
Nitrogen preservation system allows for oil expansion and contraction. It insures no moisture and no oxygen are introduced in the transformer compartments. The Nitrogen system and the nitrogen-filled bottles require frequent visits for monitoring and bottle replenishment. The schedule-based visits may either be too late or too early for the nitrogen replacement. This may lead to establishing vacuum above the oil in the transformer. This, in turn, can lead to bubble formation in oil and premature transformer failure. If the monitoring is provided remotely, the crew could be sent to replace the bottles timely and based on real conditions. Remote monitoring can also timely alarm the maintenance about the leaks in the preservation system.

Remote Oil Level monitoring insures fast response time in case of the oil leaks. Oil leaks may lead to serious environmental impact and to catastrophic transformer failures.

Supplemental Information:

- Alternatives:
  Increase inspection frequency.

- Risk of No Action:
  Increased chance of transformer failures and environmental impact.

- Non-financial Benefits:
  Non-financial benefits are: improved safety, reduced risk of oil spills (environmental impact), increased reliability.
- Technical Evaluation/Analysis:
  Governor's Island incident resulted in a major oil spill. Almost a third of the main tank transformer oil (1,000 Gallons) managed to escape the moat through a crack and spilled into New York Harbor. The Company suffered heavy fines from several local, state and federal agencies

and had to pay for the cleanup. The reason for the transformer leak was a tiny pinhole in the radiator – the result of corrosion in a salty and moist environment. An alarm about low oil level could have prevented such a large spill and limited the environmental impact from it. Due to very light load the transformer did not fail from the loss of oil in this case. However, for the oil-immersed transformers, the oil is the only heat removing medium. If the oil is removed, the winding of a transformer under normal load would overheat and fail.

- Project Relationships (if applicable):
  The stations will require new level monitoring equipment if the level switches that exist at many stations are not in working condition. The status information will be passed into the data concentrator at each station. From there, changes will need to be made in XA-21 and PI to account for the new points.

- Basis for Estimate:
  - Equipment cost per station (wiring, conduits, switches, I/O module): $3,000
  - Labor cost per station (3 days field work, 1 day programming): $17,600

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	54	41	41	41	41
M&S	-	-	-	-	-
A/P	200	400	400	399	399
Other	18	35	35	35	35
Overheads	27	25	24	24	24
Total	**300**	**500**	**500**	**500**	**500**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Unit Substation Upgrade and Improvement
Project Manager	Andrew DePippo
Hyperion Project Number	PR.23545494
Status of Project	Planning
Estimated Start Date	Spring 2019
Estimated Completion Date	Fall 2024
Work Plan Category	Operational Reliability

Work Description:
This program will address corrective actions required to repair any deteriorated conditions that could lead to a potential safety, environmental or structural issues involving any of the 239 unit/multibank substations on our system. These deteriorated conditions include repairs to the transformer and switch gear pads, transformer moats and switchgear housing, station fencing and retaining walls, driveways, walkways, sidewalks, stairways, entrances (includes gates), station and security lighting. In addition to these civil improvements, there are both equipment and electrical items that if found defective will need replacement or upgrade.

Proposed equipment upgrades include the purchase and installation of XFMR Maypole fall protection systems.

Justification Summary:
This program currently takes into account all 239 unit/multibank substations. Defects in these areas when left unaddressed areas can lead to safety concerns for our employees and the public, hinder operations causing delaying in the processing feeders and comprise reliability of the 4kv grids.

Certain types of repairs are repetitive and in cases can be cost effective when bundled with other defects in a programmatic approach.

Station lighting can be improved with newer energy efficient lighting systems to allow employees greater visibility. Unit substations are reviewed to ensure they meet Company security requirements and it is necessary to install additional perimeter security lighting systems.

Stations found to require repetitive repairs due to water leaks will be reviewed to determine the integrity of its roofing system. Those stations found with their integrity comprised will be a candidate for a new roofing system made by either the Carlisle or Kemper roofing systems.

New or upgraded systems including; on line monitoring, water sprinkler, cooling fans, and water taps for station use (water meter pit) are required to meet the operation needs of the station.

Supplemental Information:

- Alternatives:
  - Address the repairs individually and under the current O&M program. The volume of repairs is projected to rise if a long term strategy is not followed.
  - Retire existing equipment and replace with a new unit substation.

- Risk of No Action:
  Deteriorated conditions if left unaddressed can lead to safety concerns for both Company employees and the public. Negative publicity from local communities as well as the risk of a safety concern that turn in to a litigation. Work load for Company resources will continue to increase challenging our man-power capability.

- Non-financial Benefits:
  None

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable

- Technical Evaluation/Analysis:
  Each project to be designed and ruled by Property Records

- Project Relationships (if applicable):
  None

- Basis for Estimate:
  Historical unit cost for similar type projects.

Total Funding Level ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	76	76	75	75
M&S	-	-	-	-	-
A/P	-	806	806	808	808
Other	-	72	72	72	72
Overheads	-	46	46	46	45
Total	**-**	**1,000**	**1,000**	**1,000**	**1,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Vented Service Box Covers (Includes Manholes)
Project Manager	James Leary
Hyperion Project Number	PR.6ED8101
Status of Project	In Progress
Estimated Start Date	1/1/2019
Estimated Completion Date	12/31/2022
Work Plan Category	Strategic

Work Description:

This program funds the targeted installation of vented *metal* covers on structures located in street crosswalks and vented *composite* covers on structures located in sidewalks. The program entails identifying structures that have elevated risk to public safety and replacing solid covers with vented composite covers on sidewalks. Previously, structures have been vented on larger scale with the goal of replacing as many covers as possible. While most covers have been replaced, there remain approximately 100,000 unvented structures on the system.

The scope of work for this program is to install vented cover panels on structures that have been identified as having the highest benefit to public safety as follows:

1) Structures located in higher pedestrian traffic areas, such as crosswalks, may benefit from venting. If a cable were to fail, the resulting gases could vent to the atmosphere, reducing the potential of an event and risk to pedestrians.

2) Emergent structures for venting may be selected based on past events, new data analytics, or geographical and logistic concerns.

3) Structures with cables and cable combinations having elevated failure rates may also be considered independently for venting. These structures may tend to experience more events and thus also benefit from a vented cover.

The program plan is to install vented covers on approximately 3,000 structures over the next 4 years. Some structures must be enlarged to accommodate vented cover installations. The plan for the enlargements associated with vented cover panel installations is to enlarge approximately 10 structures per year.

High Level schedule (2019 – 2022)

Description	2019	2020	2021	2022
	Estimated Structure Counts			
Pedestrian cross walk & Plaza	500	500	500	500
Emergent Structures	200	200	200	200
Enlargement	10	10	10	10
Totals	710	710	710	710

Table 1

Justification Summary:
The installation of vented covers helps reduce the buildup of combustible gases associated with events on the low-voltage secondary system thereby reducing the severity of underground events and enhancing public safety. Venting underground structures reduces the available energy during an event and reduces the potential for injury or mechanical damage. The installation of vented composite, i.e., electrically insulating, covers on the sidewalks will enhance public safety by mitigating stray voltage in addition to facilitating the escape of combustible gases. Since the inception of the program in 2004, underground structure events have been reduced by 22% (2013), while Company related electric shock reports have been reduced by 78%.

Property damage associated with manhole events has also been reduced (15% reduction).

Supplemental Information:

- Alternatives:
  An alternative for reducing the buildup of combustible gases include placing positive displacement devices in the structures. This alternative is in the development stages and may be more expensive. In order to mitigate manhole explosions both methods may be used in the future.

- Risk of No Action:
  No action may result in an increase in the severity and volume of underground events, and may increase stray voltage/energized metal covers on sidewalks and associated public safety concerns.

- Non-financial Benefits:
  This program is not mandated by the Public Service Commission. However, the installation of vented service box covers improves public safety by reducing the number and severity of underground events as well as mitigating stray voltage conditions.

- Summary of Financial Benefits (if applicable) and Costs:
  This is an ongoing program. Through competitive bids, the company has been able to maintain lower costs in the Vented Service Box Cover Program. The program costs include the cost of the metal or composite vented covers, installation, and civil work (enlargements). The current average cost per installation in 2018 is approximately $1000.

- Technical Evaluation/Analysis:
  The installation of vented service box covers reduces the likelihood of underground structure events by reducing the buildup of combustible gases, which are produced by failing cables. Electrical Power Research Institute (EPRI) testing results indicate that the success of vented covers in reducing cover dislodgement. The installation of vented manhole covers has successfully validated the effect of ventilation in mitigating secondary events. In addition, smoke emitted through the ventilated cover creates a visible indicator, and alerts the public to stay away from the structure.

  Installation of composite covers helps mitigate stray voltage conditions, and reduces the potential for electric shock incidents.

- Project Relationships (if applicable): None

- Basis for Estimate:
  The basis for this estimate is the historical unit cost for replacing solid cover panels on a structure along with any necessary civil work. The historical unit cost is approximately $1000 and the cost for an enlargement $5,000

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	8	3	210	516		642
M&S	2,123	976	2,902	4,046		1,794
A/P	1,713	459	1,475	853		1,205
Other	8	25	146	192		526
Overheads	1,890	576	1,572	1,629		1,380
Total	**5,742**	**2,039**	**6,305**	**7,236**		**5,547**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	93	94	93	93	93
M&S	295	348	365	355	360
A/P	161	161	161	161	161
Other	41	46	48	47	47
Overheads	410	352	333	344	339
Total	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**

Schedule 4:

T&D O&M White Papers

Risk Reduction

	Capital
X	O&M

2020 – Electric Operations

Project/Program Title	Emergency Response
Project Manager	N/A
Status of Project	On-going
Estimated Start Date	On-going
Estimated Completion Date	On-going
Work Plan Category	Operationally Required

Work Description:
The Emergency Response program is comprised of the following individual work functions:

1) **Contingency** – This initiative provides a reserve of funds intended to offset unforeseen expenses that may arise because of system emergencies;

2) **Obstructed Ducts** – This program addresses several tasks associated with maintenance of blocked underground conduit. These tasks include:
   - Clearing duct obstructions with a rodding tool and flushing equipment;
   - Maintenance activities associated with clearing obstructed ducts carrying primary or secondary conductors, including the breaking and excavation of duct along with any associated backfilling and paving;
   - Clearing obstructed ducts for underground services and street lighting;

3) **Customer Investigations** – This budget is used to investigate service complaints on customers' premises, including the labor associated with "no lights" investigations which subsequently reveal the outage cause to be faulty customer equipment;

4) **Burnouts – URD** – This program accounts for the minor repair and remake of splices on primary, secondary, and service URD cables resulting from burnouts. Restoring customer premises during emergency URD service repairs, along with any excavation and backfilling, is accounted for as well;

5) **Burnouts – Flush** – In order to provide a safe environment for our employees who work within underground structures, the cleaning of manholes, service boxes and vaults is necessary particularly when access is required with little advance notice. The most effective way to provide this support to emergency crews is to have flush truck resources and personnel ready when burnouts and other service outages occur. This program accounts for all activities associated with cleaning and flushing manholes and service boxes as a result of underground primary, secondary, or service burnouts/emergencies;

6) **Burnouts and Emergency Related** – This program is comprised of the following emergency maintenance activities:
   - Operation of switches or station equipment
   - Installation and removal of field grounds for fault readings
   - Grounding and identification of feeder phasing
   - Grounding and phase fault locating
   - Emergency repairs to overhead or underground street light services
   - Emergency overhead facilities repairs
   - Maintenance of primary or secondary cables resulting from burnouts
   - Repair of impending hazardous faults, or "D" faults, on feeders
   - Emergency repairs to overhead or underground services to resolve outage complaints from customers
   - High tension switch moves on customer premises from the District Operator
   - Maintenance of underground electric cables damaged by underground incidents;

7) **Burnouts or B Tickets – Overhead** – This initiative accounts for several maintenance activities associated with overhead burnouts. They are:
   - Maintenance of poles and fixtures during non-capital emergency work
   - Maintenance of overhead primary, secondary, or service conductors and devices during non-capital emergency work;

8) **Burnouts or B Tickets – Underground** – This initiative accounts for several maintenance activities associated with underground burnouts and potential faults. They are:
   - Maintenance activities associated with underground conduit during emergencies
   - Minor repairs, such as piece-outs or joint remakes, on primary feeders resulting from emergencies or OAs
   - Minor repairs, such as "re-crabbing" (joint remakes), on secondary mains resulting from emergencies
   - Corrective maintenance for potential impending faults, or "C" faults, on primary feeders
   - Service maintenance repairs, such as installing or removing temporary services, resulting from underground emergencies
   - Sealing ducts that enter customers' premises to prevent water leaks;

9) **Storm Reserve** – On occasion, the Company may experience significant damage to its electric overhead systems due to storms. The Public Service Commission (PSC) in its Order in case 08-E-0539 approved the establishment of a Storm Reserve which may be utilized in instances where a storm meets certain criteria. The PSC recognizes three storm categories from least to most severe, numbered 1, 2, and 3. The storm reserve can be used for PSC Categories 2 or greater and for mobilization in advance of a storm anticipated to meet the criteria for a Category 2 or greater;

10) **Emergency Diesel Generators** – Mobile generators and their associated equipment provide support to the electric distribution & transmission systems and substations, steam, gas, and other facilities during emergency outages. They also assist in providing critical electric system support by de-loading in-service equipment that may be severely overloaded. This program addresses the maintenance and mobilization of Company owned mobile generators and the rental of vendor generators, transformers, cables, and the transportation of such equipment;

11) **Overhead Storm Emergency** – This program accounts for several maintenance activities undertaken due to major overhead storm emergencies. They are:
- Maintenance of poles and fixtures
- Maintenance of primary, secondary, or service conductors and devices
- Company and/or contractor tree trimming, where the overhead system exists
- Labor and other non-field related expenses incurred in support of field activities during storm emergencies.

In order for the Company to secure overhead resources for future storms, as well as increasing its overall storm preparedness, it is proactively securing retainers with overhead contractors. These retainers require the selected contractors to guarantee a total of 101 overhead line resources for Con Edison. In addition, the retainer requires the contractors to provide the Company the "First Right of Refusal" during times or storm events where other utilities could be looking to secure resources. This option provides the Company security by not jeopardizing the guaranteed resources allocated to Con Edison.

This program will also fund the 2020 Flush Allocation Process. Flush costs are accumulated in Gross Clearing Accounts assigned to each region. Prior to the implementation of Project Accounting (EBS) and Electric WMS (Logica), these costs were distributed for Burnout Activities only via a Corporate Authority Letter. Historically, this allowed for both the clearing process for Flush work related to "burnouts", and direct charging to specific projects.
Due to system integrations and obsolescence of the previous system that managed Flush work (i.e. Vactor System) it became necessary to utilize WMS (Logica) and expand the "clearing" process to all Flush work.

Justification Summary:
In recent years, obtaining overhead contractor resources for mutual assistance has become more challenging as other utilities also are in need of the same resources. The impact of not having contractor resources readily available for mutual assistance purposes became evident during the March 2018 nor'easter storms (Riley/Quinn). One of the post storm recommendations, was to find a better way to guarantee overhead FTE resources.

For the 2020 Flush Allocation Process, the allocation to O&M, Capital and Retirement was based on historical data collected by the now retired DOCS Work Management System related to Burnout Expenditures. The non-Burnout portion of Flush was a 'direct charge' to the actual job requiring a Flush. This historical basis was combined to include adjustments to the authority letter for the direct charges. This has been kept in place for the current rate case period.

In addition, the basis for the allocation was retained due to system application development and the need for operations to fully learn and adapt to the new process.

Data from the new Electric WMS system has been collected to determine a new allocation (new basis) to be used for all Flush Activity effective in 2020. The new process determines the allocation to be applied to the authority letter based on the source work of the Flush activity. This will represents 100% of all the Flush Activity for the field crews. There will be no direct charging for Flush activity to specific projects.

Risk of No Action:
Failure to enter into an agreement with a contractor to secure overhead resources for severe storms will hinder the Company's ability to provide additional and earlier access to worker resources; improve mutual aid response, proactively recruit contractors for faster response after severe storms, and secure

access to bucket trucks for mutual aid crews as soon as they arrive. It will also hinder the Company's ability to prioritize roads for clearing and critical facilities; leading to less collaboration with municipalities to identify and prioritize critical facilities and roads for clearing. Finally, failure to implement such a program will weaken Con Edison's municipal liaison program due to lack of dedicated resources to give liaisons better information regarding crews and restoration.

Non-financial Benefits:
The benefits of this retainer is twofold. It would help ensure supplemental resources for weather related events, as well as provides Con Edison greater transparency for when the overhead contractor resource pool begins to become depleted; thus allowing the Company to make more informed decisions when trying to secure these overhead resources.

Summary of Financial Benefits (if applicable) and Costs:
The retainer is estimated to cost a total of approximately $2M per year and will be paid on a quarterly basis.

The implementation of Logica as the source of our Flush Cost allocation in 2020 will have the following impact to O&M, Capital and Retirement:

- O&M +3 million
- Capital +6 million
- Retirement -9 million

Basis for Implementation Estimate:
None

Annual Funding Levels ($000)*:

Incremental Change due Flush Allocation and Retainer to Emergency Response program
Future Elements of Expense (Does not include Hellgate Wharf Refurbishment or AMI Electric Operations)

EOE	Request 2020	Request 2021	Request 2022	Request 2023
Labor	3,500	-	-	-
M&S	-	-	-	-
A/P	2,000	-	-	-
Other	-	-	-	-
Total	**5,500**	**-**	**-**	**-**

Historical Elements of Expense total Emergency Response program

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Actual 2018
Labor	88,491	100,222	93,232	92,718	103,378	105,751
M&S	2,900	4,865	5,191	3,865	5,877	4,241
A/P	11,741	11,708	14,554	14,476	21,393	18,751
Other	8,630	13,057	14,518	17,284	19,587	19,222
Total	**111,762**	**129,852**	**127,496**	**128,347**	**150,234**	**148,241**

Future Elements of Expense total Emergency Response program

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	89,601	91,443	90,550	89,068	89,068
M&S	4,135	4,135	4,135	4,135	4,135
A/P	14,259	18,063	18,283	18,283	18,283
Other	14,166	14,166	14,166	14,166	14,166
Total	**122,160**	**127,806**	**127,133**	**125,651**	**125,651**

*Includes dollars from the Hellgate Wharf Refurbishment and the reduction in dollars due to AMI project. See the Hellgate Wharf Refurbishment and AMI Electric Operations white papers.

	Capital
X	O&M

2020 – Electric Operations

Project/Program Title	ARCOS Enhancement
Project Manager	Jackson Koo
Status of Project	Pending
Estimated Start Date	2018
Estimated Completion Date	2020
Work Plan Category	Strategic

Work Description: ARCOS (Automated Roster Call Out System), is a software system that provides automated crew callout and resource management capabilities through their suite of solutions that includes:

ARCOS Callout and Scheduling
ARCOS Crew Manager
ARCOS Resource Assist / SMART
ARCOS Mobile

The Company currently uses the following two applications; ARCOS Callout and Scheduling solution. These two applications will be expanded to include the entire suite of solutions listed above. The use of all of these applications will streamline the existing crew callout, System Emergency Assignment (SEA), and crew management processes into a single solution resource that encompasses all internal employees and external contractors/mutual assistance crews. This approach of using the entire suite for both blue-sky and storm situations provides an end-to-end solution that eliminates the need to use risky storm-only solutions with higher learning curves and low user familiarity. In addition, the mobile application capabilities will enhance front-line user engagement and compliance with corporate policies and labor agreements.

Funding provides for the maintenance and use of the computer hardware and software for this application.

Justification Summary: Currently, the Company uses several software applications to perform the functionality of the entire existing ARCOS suite of products. ARCOS Callout and Scheduling is used for limited callouts for overtime/emergency staffing and SEA activation. The SEA program is currently managed by a manual process through a stand-alone application. Resources on Demand (RoD) is used to manage external contractors and mutual assistance resources during storm events.

Several of the existing software applications will be affected in the near future. RoD was purchased by ARCOS in 2016 and will be retired in 2019.

The After Action Report/Improvement Plan (AAR/IP) for winter storms Riley and Quinn has made a number of recommendations to improve operating efficiency by greater utilization of the software we already have in place, and by expanding the use of these applications. Interfacing with the other systems mentioned would provide for a much more efficient means of accounting for resources, assigning work, and managing incident response, especially when responding to queries from the Public Service Commission (PSC).
In addition to the annual maintenance of the SEA module system, we are looking to make enhancements. These enhancements will provide the Company with additional capabilities that provide real-time

information for storm role owners, leadership, and managers. Currently, the system has limited reporting capabilities and requires manual configurations of reports from different systems. Considerable time is spent generating these reports. These real-time viewing and reporting capabilities will allow better decision-making for staffing resources. And with increased requests from both internal and external agencies for such staffing information, these enhancements will expedite the process to provide the necessary information in a timely manner.

Implementation of this project would allow for the consolidation of functions into one end to end system and would enable the Company to retire the SEA legacy system and RoD self-hosted system. These enhancements will also provide better notifications to employees and/or other staffing resources that are utilized during blue-sky day or emergency events.

Supplemental Information:

- Alternatives: The alternative is to continue to manually manage internal and external resources, report on these resources, and consolidate information.

- Risk of No Action: By not upgrading the existing software, the Company will continue to rely on multiple stand-alone applications that rely on manual processes to coordinate their inputs and outputs to manage our resources. The Company would not benefit from the efficiency gains offered by increased functionality of the new software. Additional time and resources will continue to be tied up as the current manual processes of crew callouts and resource management will lead to longer restoration times, especially during storm events. The Company may also be subjected to fines from our regulators if we are unable to provide information of our restoration status in a timely manner, as per regulatory requirements.

  Several of the existing software applications will be affected in the near future. RoD was purchased by ARCOS in 2016 and will be retired in 2019.

- Non-financial Benefits: The enhancement with ARCOS software suite will increase the Company's ability to monitor staff and resources, send notifications to employees in an expedited and efficient manner, and create real time reports during events. It will allow a single solution to integrate several critical functions. It will also allow the retirement of four legacy systems hosted on company servers.

- Summary of Financial Benefits (if applicable) and Costs: Costs associated with enhancements are provided below.

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable): ARCOS upgrades are linked with the RoD project.

- Basis for Estimate: Estimate from vendor based on enhancement costs.

Total Funding Level ($000):

O&M

Engineering and Other Services

Incremental Change due to this project to the Engineering and Other Services program
Future Elements of Expense

EOE	Budget 2020	Request 2021	Request 2022
Labor	-	-	-
A/P	1,000	-	-
M & S	-	-	-
Other	-	-	-
Total	**1,000**	**-**	**-**

Historical Elements of Expense total Engineering and Other Services program

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Actual 2018
Labor	6,139	6,328	6,468	6,347	5,851	5,417
M&S	191	213	147	76	36	32
A/P	987	1,525	603	1,929	882	319
Other	17,427	18,779	18,918	20,469	21,512	21,911
Total	**24,744**	**26,845**	**26,136**	**28,821**	**28,281**	**27,679**

Future Elements of Expense total Engineering and Other Services program

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	5,531	6,811	6,811	6,811	6,811
M&S	33	33	33	33	33
A/P	326	3,646	3,846	4,326	4,326
Other	22,372	22,372	22,372	22,372	22,372
Total	**28,261**	**32,861**	**33,061**	**33,541**	**33,541**

	Capital
X	O&M

2020 –Central Operations/Substation Operations

Project/Program Title	Roof and Structural Repairs Program
Project Manager	Various
Hyperion Project Number	Not Applicable
Status of Project	Planning
Estimated Start Date	2020
Estimated Completion Date	2022
Work Plan Category	Operationally Required

Work Description:
The objective of this program is to repair the roofs and facades of substation facilities. This O&M program would address the repairs that would alleviate current deteriorated roofs and facades which are not currently candidates for a full replacement.

The operations and maintenance expense is estimated to address five roof repairs (~$30K) and one façade projects (~$500K) per year.

Justification Summary:
The Company has an ongoing program to inspect each of the 554 substation roofs approximately once every five years (more frequently for older roofs, less frequently for newer roofs), averaging 100 roofs per year. These inspections identify candidates for the capital Roof Replacement program as well as potential repairs where applicable.
This request proposes the establishment of a comprehensive maintenance program to correct material issues which can no longer be addressed through routine maintenance. This program would cover impacted areas which include major sections of the structure, both interior and exterior, that are too significant to be addressed with minor repairs but are not candidates for a full replacement.

Supplemental Information:

- **Alternatives:**
  SSO:
  One alternative is to continue to rely on the capital program for full roof/façade replacements.

- **Risk of No Action:**
  SSO:
  Structural conditions at targeted locations could continue to degrade if no action is taken. These conditions could reach the point where equipment availability is affected or conditions are unsafe for personnel.

- **Non-financial Benefits:**
  SSO:

In addition to an improvement in personal safety, this program may reduce costs associated with temporary engineering controls to mitigate leaks and other structural damage. Furthermore, clean-up costs associated with leaking roofs and facades may be reduced.

- **Summary of Financial Benefits (if applicable) and Costs: NA**

- **Technical Evaluation/Analysis:**
  Central Engineering has also established an inspection program to monitor and assess the structural condition of substation facilities (external and internal) to ensure safe conditions for members of the public, company employees and the equipment housed in the facilities.
- **Project Relationships (if applicable): NA**

- **Basis for Estimate: Order of magnitude Estimate:** SSO Estimate

Annual Funding Level ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P						
Other						
Total	**-**	**-**	**-**	**-**	**-**	**-**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	-	-	-	-	-
A/P	-	650	650	650	650
Other	-	-	-	-	-
Overheads	-	-	-	-	-
Total	**-**	**650**	**650**	**650**	**650**

	Capital
X	O&M

2020 – Electric Operations

Project/Program Title	Tree Trimming
Project Manager	Tom Zazzarino
Status of Project	Ongoing
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:

Line clearance is to be performed on the overhead electric distribution lines in accordance with EO-10353. In 2007, Con Edison developed an enhanced Line Clearance program that incorporated appropriate risk prevention and mitigation strategies designed to improve electric reliability. Also implemented was an aggressive communications strategy with our customers and other stakeholders to provide more timely and accurate information regarding the program. Another main element of this enhanced program was increased clearances along our Right of Way in the Line Clearance specification for Electric Operations.

In addition to specification driven line clearance, trees considered to be danger trees will be removed. Removal program will target the annual removal of 1,400 danger trees.

Justification Summary:

Trimming tree growth is critical to operating on overhead distribution system. Untrimmed trees will grow into distribution lines and cause customer outages and physical damage to the distribution system.

A danger tree is any tree on or off the right of way that could contact electric supply lines. A hazard tree is a structurally unsound tree that could strike electric supply lines when it fails. As shown during major storms, electric facilities are subject to significant damage from fallen trees. Even a healthy, apparently sound tree constitutes a risk to electric facilities. While the risk of failure of a tree may not be known, we know that all trees can fail given enough stress loading and consequently, the risk is not zero. Therefore, in addition to all hazard trees, all danger trees are a liability to electric overhead facilities. By only targeting hazard tree removals, the risk of tree-caused outages would not be reduced to zero. In order to increase the effectiveness of a targeted tree removal program, the scope of work is to include danger tree removals.

Supplemental Information:

- Alternatives:
  The only alternative to implementing an enhanced Line Clearing program would be for the Company to take the risk that overhead infrastructure will become damaged by overgrown trees during harsh weather. The alternative would be detrimental because it would require the Company to conduct emergency repairs of damaged infrastructure which would be much more costly than implementing the enhanced Line Clearance program. Moreover, conducting emergency repairs on damaged infrastructure would lower customer satisfaction due to increased power outages.

- Risk of No Action:
  Without a Line Clearance program increased outages would result in poor performance in the SAIFI, CAIDI and major storm response metrics. Poor performance in these categories can lead to financial penalties in the form of Reliability Performance Mechanisms.

  Without a danger tree program, significant overhead electric facility damage will occur as was experienced in 2018 Nor'easter Quinn and Nor'easter Riley storms.

- Non-financial Benefits:
  As part of this program there has been increased communication with, and education of, our customers on the need for our clearance program to remain constant. Timely and reliable communication of the Line Clearance program has helped enhance public acceptance. We continue to utilize various forms of media including mailings, notification foresters, and community days for outreach and education. This has increased public satisfaction.

- Summary of Financial Benefits (if applicable) and Costs:
  None

- Technical Evaluation/Analysis:
  See Justification Section

- Project Relationships (if applicable):
  None

- Basis for Estimate:
  Historical unit cost. Quoted cost for a tree removal.

Total Funding Level ($000):

Incremental Change
Request by Elements of Expense

EOE	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-
M&S	-	-	-	-
A/P	2,000	-	-	-
Other	-	-	-	-
Total	**2,000**	-	-	-

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Actual 2018
Labor	796	825	962	900	711	655
M&S	2	2	6	1	25	34
A/P	11,564	14,248	10,526	9,833	11,066	11,511
Other	95	42	123	36	17	225
Total	**12,458**	**15,117**	**11,618**	**10,770**	**11,819**	**12,425**

Request by Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	683	683	683	683	683
M&S	35	35	35	35	35
A/P	11,996	13,996	13,996	13,996	13,996
Other	234	234	234	234	234
Total	**12,949**	**14,949**	**14,949**	**14,949**	**14,949**

Exhibit__(EIOP-6)

Replacement

Schedule 1: T&D Replacement Capital Program and Project Summary

Electric T&D		Year Total			
Replacement		Current Budget			
		Total Dollars ($000)			
		RY1	RY2	RY3	3 Yr. Total
Replacement					
Organization	**White Paper**				
Substations	Failed Substation Equipment Other Than Transformers	6,500	6,500	6,500	19,500
Substations	Failed Substation Transformer Program	30,000	30,000	30,000	90,000
Distribution	Overhead	39,775	40,625	38,825	119,225
Distribution	Primary Cable Replacement (OA's)	93,000	93,000	93,000	279,000
Distribution	Secondary Open Mains	153,000	153,000	153,000	459,000
Distribution	Service Replacements	68,000	68,000	60,000	196,000
Distribution	Street Lights (incl. conduit)	27,235	27,235	20,235	74,705
Distribution	Targeted Primary DBC Replacement	10,000	14,000	14,000	38,000
Distribution	Transformer Installation	35,890	35,890	35,890	107,670
Transmission	Transmission Failures - Other	976	1,000	1,000	2,976
Transmission	Transmission Feeder Failures	10,000	10,000	10,000	30,000
TOTAL ELECTRIC					
	Total Replacement	**474,376**	**479,250**	**462,450**	**1,416,076**

Schedule 2:

T&D Capital White Papers

Replacement

X	Capital
	O&M

2019 – Central Operations/Substation Operations

Project/Program Title	Failed Substation Equipment Other Than Transformers.
Project Manager	Seda Steck.
Hyperion Project Number	PR.2ES7700
Status of Project	In-Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This on-going program provides for the restoration work required to replace or perform capitalized repairs on various pieces of equipment in order to maintain our high levels of system reliability. This program funds unanticipated failures of any substation equipment other than excluding transmission and sub-transmission transformers, phase angle regulators and reactors). Equipment typically replaced by this program includes circuit breakers, capacitor banks, L&P (Light & Power) transformers, bus, disconnect switches, potential transformers, and coupling capacitor potential devices in our area and transmission substations.

Justification Summary:
This is an on-going program with funding based on historical spending levels. This program is necessary to fund the restoration of unanticipated equipment failures to maintain system design configurations and reliability. This program helps minimize the need to reallocate resources from other capital projects and programs in response to unanticipated equipment failures.

Supplemental Information:

- Alternatives: The only alternative is to not provide funding for potential failures. This is not recommended as it would necessitate the required replacement of failed equipment to be funded by diverting funds from other projects which would cause delays and increase the overall cost of these projects. These funding delays would lead to decreased system reliability and longer outage durations.

- Risk of No Action: Taking no action is not recommended as it would lead to decreased system reliability and longer outage durations. It would also necessitate the required replacement of failed equipment to be funded by diverting funds from other projects, causing potential delays and increasing the overall cost of making such repairs.

- Non-financial Benefits: This program helps avoid impacts to related projects, improves planning, and enables a more efficient use of capital dollars. Since this program provides funding that can be drawn on when a failure occurs, it reduces the need to constantly re-prioritize and deal/defer in flight work to provide funding when a failure occurs. This program also helps maintain our reliability levels, as it replaces failed equipment and allows our station design standards to be met.

- Summary of Financial Benefits (if applicable) and Costs: NA

- Technical Evaluation/Analysis: NA

- Project Relationships (if applicable): All projects funded under this program are a result of equipment failure (excluding transformers) in substations.

- Basis for Estimate: Funding request based on historic actual expenditures for the years 2014, 2015, 2016, and 2017.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	2,386	1,228	3,266	3,016		7,014
M&S	1,489	1,477	2,349	3,151		5,379
A/P	524	780	1,145	407		3,009
Other	100	(301)	(464)	548		837
Overheads	3,218	2,098	3,496	3,089		6,475
Total	**7,717**	**5,282**	**9,793**	**10,211**	**-**	**22,714**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,749	1,820	1,820	1,820	1,820
M&S	1,811	1,885	1,885	1,885	1,885
A/P	562	390	420	449	423
Other	214	218	217	218	218
Overheads	1,909	2,187	2,158	2,128	2,154
Total	**$6,245**	**$6,500**	**$6,500**	**$6,500**	**$6,500**

X	Capital
	O&M

2019 – Central Operations/Substation Operations

Project/Program Title	Failed Substation Transformer Program
Project Manager	Henry Nguyen
Hyperion Project Number	PR.2ES7600
Status of Project	In-Progress
Estimated Start Date	N/A
Estimated Completion Date	N/A
Work Plan Category	Operationally Required

Work Description:
This ongoing program provides funding for the restoration work required to replace transformers in our Area and Transmission Substations on an emergency basis (whenever they unexpectedly fail). Con Edison maintains an inventory of various voltage and MVA classes, which can be used in the event of a failure. In virtually all cases, a like-in-kind replacement unit is available for use as a permanent replacement for a failed unit. These units are transported to the facility where they are required and installed. A replacement unit is then purchased and put back into the spare transformer inventory.

Justification Summary:
This ongoing program covers the cost of replacing three failed transformers (transformers, phase angle regulators and reactors) per year, which is based on the historical average failure rate of 0.76%. The cost includes the installation of an existing system spare, and the purchase of a replacement for the utilized system spare. To quickly restore system capacity and reliability to pre-failure levels, spare transformers are maintained for most types of units in the system. The spare units are purchased and kept on hand due to the long lead-time required for delivery of a new transformer. The spare units are pre-tested and partially assembled to reduce the time required for replacement of a failed unit. The spare units are prepared for long-term storage at the Astoria Spare Transformer Yard and at other Company satellite locations.

Supplemental Information:

- Alternatives: There is no alternative to replacing a failed transformer.

- Risk of No Action: The risk of no action can jeopardize the reliability of the distribution and transmission System. If multiple failures were to occur during a high load period or while other critical facilities are out of service, load shedding and large-scale customer outages can result.

- Non-financial Benefits: This program aims to provide reliable, uninterrupted service to our customers. By maintaining an inventory of system spares, work on replacing a failed unit can begin immediately, rather than waiting for a replacement unit to be located and purchased.

- Summary of Financial Benefits (if applicable) and Costs: Primary benefit of undertaking this program is improved reliability.

- Technical Evaluation/Analysis: N/A
- Project Relationships (if applicable): N/A
- Basis for Estimate: This funding level has been set based on our recent actual replacement costs, and assumes 3 failures/year.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	2,058	4,957	2,487	9,834		2,941
M&S	8,216	10,985	7,649	11,526		20,527
A/P	334	1,395	1,577	6,061		2,405
Other	22,661	1,936	554	2,300		1,117
Overheads	4,951	10,289	4,410	11,816		7,041
Total	**38,221**	**29,562**	**16,676**	**41,539**	**-**	**34,032**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	5,996	5,996	5,996	6,000	6,000
M&S	10,493	10,192	10,313	10,500	10,350
A/P	3,597	2,998	3,007	3,000	3,000
Other	1,631	1,553	1,557	1,504	1,524
Overheads	8,283	9,261	9,127	8,996	9,126
Total	**30,000**	**30,000**	**30,000**	**30,000**	**30,000**

X	Capital
	O&M

2020 Capital – Electric Operations

Project/Program Title	Overhead Emergency Response
Project Manager	Not Applied
Hyperion Project Number	PR.20451610, PR.20451611, PR.20456590, PR.20456591, PR.2ED5011
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program provides funding for high-priority emergency work to replace non-network overhead and Underground Residential Distribution (URD) infrastructure and associated equipment after failure or when imminent failure is identified as a result of diagnostic testing such as infrared, ultrasonic, or visual inspection. Such equipment includes cable, URD, and overhead transformers and open-wire along with associated structures and accessories. The projected annual number of units is listed below. Actual units repaired will depend on a number of factors including weather, and the amount of inspection and testing performed in a given year.

Item	**Units Per Year**
Overhead transformers	152
URD Transformers:	57
Poles, Towers & Fixtures:	1,270
OH Primary Sections:	1,635
OH Secondary Sections:	2,090
OH Services:	2,225
OH Street Lights Services:	976
OH Aerial Cable Sections:	300
URD Primary Conductor:	18

Justification Summary:
Failed equipment or equipment identified as being in danger of imminent failure must be replaced. Equipment failures often cause customer interruptions and the restoration of those customers and normalization of the system typically involves replacement of failed equipment. Equipment identified as being in danger of imminent failure presents both a reliability and safety risk and must be addressed by replacement. This program supports the objective of meeting PSC reliability performance goals (SAIFI and CAIDI).

Supplemental Information:

- Alternatives:
  The alternative to emergency response to non-network equipment failure is to delay replacement and schedule the repair work at some future time. This alternative would be only slightly less

costly and would, at times, result in customers remaining out of service for extended periods of time or leave the system in an abnormal, vulnerable configuration without backup sources of supply.

- Risk of No Action:
  No action on this program would result in customers remaining out of service for extended periods of time and the system remaining in an abnormal, vulnerable configuration without backup sources of supply. This would also present a public safety risk for equipment identified in imminent danger of failure, and a reliability risk for both failing and failed equipment as the system would be in a vulnerable configuration until restored.

- Non-Financial Benefits:
  This program helps mitigate public safety risk including hazards associated with downed wires and hit poles. In addition, this program reduces the environmental impact associated with leaking and/or damaged transformers and other equipment.

- Summary of Financial Benefits:
  The PSC sets reliability performance standards (SAIFI and CAIDI) that the Company must meet. Reliability performance not meeting threshold targets may expose the Company to as much as $10 million in penalties ("Radial SAIFI" and "Radial CAIDI") under the current rate agreement. Addressing failing and failed equipment will reduce the potential that the Company will incur financial penalties due to non-compliance with reliability standards.

- Technical Evaluation/Analysis:
  See Justification section

- Project Relationships (if applicable):
  None

- Basis for Estimate
  The basis for this estimate is the historic unit cost for each of the following:
    - Overhead transformers
    - URD Transformers
    - Poles, Towers & Fixtures
    - OH Primary Sections
    - OH Secondary Sections
    - OH Services
    - OH Street Lights Services
    - OH Aerial Cable Sections
    - URD Primary Conductor

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	12,053	15,467	19,038	20,974		24,242
M&S	3,469	3,137	3,660	4,776		3,852
A/P	3,170	2,750	2,420	2,329		14,239
Other	(441)	(2,172)	(455)	(490)		-
Overheads	12,012	16,015	15,207	15,296		18,434
Total	**30,263**	**35,197**	**39,870**	**42,885**		**60,767**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	15,071	17,662	19,399	18,988	15,888
M&S	4,144	3,431	3,729	4,324	2,524
A/P	3,768	2,984	2,466	2,109	9,332
Other	(277)	(2,695)	(464)	(444)	-
Overheads	15,071	18,393	15,495	13,848	12,081
Total	**37,677**	**39,775**	**40,625**	**38,825**	**39,825**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Primary Cable Replacement (OAs, FOTs, C&D Fault)
Project Manager	George Murray
Hyperion Project Number	PR.20451610, PR.20451611, PR.20456590, PR.20456591, PR.20455748, PR.2ED5011
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program funds emergency repair work on primary feeders (these repairs can include splicing, cable, and installation of new conduit) for the following conditions:

- Component failures (cable, splice, termination) that cause an in-service outage (OA, Open-Auto)
- Component failures caused by post maintenance High-Voltage Withstand/Hipot tests (FOT, Fail-On-Test)
- Component failures that result in a post maintenance Ammeter-Clear test failure (FOT, Fail-on-test)
- Serious degraded components that are classified as "C" or "D" faults

Units per Year:
Number of applicable feeder component repairs based on five year historical average:

- OA, 793
- FOT, 219
- C&D Faults (two year average),605
- **Total** **1,617**

High-level schedule:
The expectation is to repair approximately 1,600 primary feeder components each year due to component failure or a seriously degraded condition.

Justification Summary:
Primary feeders are the backbone of our electric distribution system. While they are reliable, component replacements are regularly required due to a failure or a serious degraded condition. Due to the criticality of maintaining primary feeders in service, we maintain a zero backlog of open primary feeders. The requested funding will keep the system at a zero backlog.
A post-maintenance High-Voltage Withstand/Hipot test is required before a primary distribution feeder returns to service following most outages, per Con Edison specification EO-4019. This test ensures the integrity of the work performed during the outage and ferrets out any additional undiscovered component faults that could lead to an in-service failure when the feeder is re-energized (CIOA, Cut-In-Open Auto).

These CIOAs have caused significant over voltage conditions on other associated network feeders, and can result in in-service feeder failures of feeders supplying the same network.

Feeder components that are found in a seriously degraded condition are typically replaced before failure. These degraded components are classified as either a "C" or a "D" fault, per Con Edison specification EO-1184. This program corrects "C" and "D" fault conditions, which enhances the safety and reliability of the distribution system.

Supplemental Information:

- Alternatives: There are no alternatives other than addressing component failures when they occur.

- Risk of No Action: Feeder component failures and the time it takes to restore the failed feeder directly impact distribution system reliability and reliable customer service. Loss of multiple feeders in the same network results in a network contingency, which, during high load conditions, can cause low voltage conditions, cascading component failures, customer outages and possibly a network shut down. Taking no action will have a significant impact on network reliability and customer service.

- Non-financial Benefits: The repair of "C" and "D" fault conditions provides significant Environment Health & safety (EH&S) to Con Edison employees and the general public by eliminating potential hazards from our underground distribution system. Over the past five years, nearly 3,000 degraded components were removed from the distribution system.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable): N/A

- Basis for Estimate: Historical unit costs

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	26,963	27,662	2,608	28,257		29,833
M&S	16,777	14,814	11,918	13,956		15,441
A/P	8,629	8,810	8,648	14,191		16,827
Other	(2,738)	3,006	5,067	6,811		-
Overheads	38,690	43,559	31,826	32,537		34,694
Total	**88,321**	**97,851**	**60,067**	**95,752**		**96,796**

Future Elements of Expense

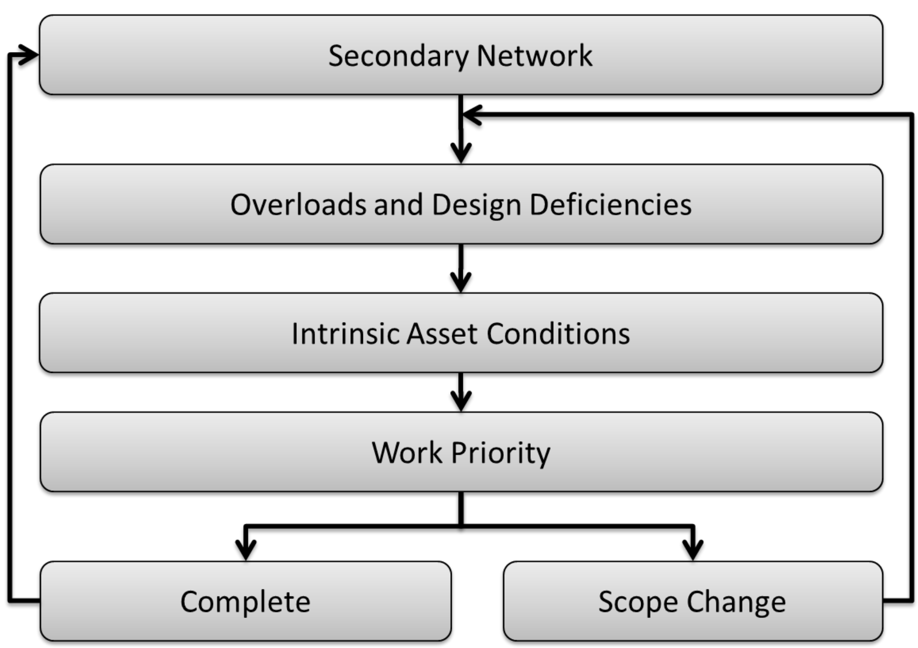
EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	27,664	26,291	4,038	27,445	28,664
M&S	17,213	14,080	18,452	13,555	14,836
A/P	8,853	8,373	13,389	13,783	16,167
Other	(2,809)	2,857	7,845	6,615	-
Overheads	39,696	41,400	49,275	31,602	33,333
Total	**90,617**	**93,000**	**93,000**	**93,000**	**93,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Secondary Open Mains
Project Manager	Stan Lewis / Mark Riddle
Hyperion Project Number	PR.2ED0161, PR.2ED4461, PR.2ED1021, PR.2ED3241, PR.2ED7661, PR.2ED7981, PR.NED5001
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
The Secondary Open Mains program involves the replacement and reinforcement of secondary cable to maintain system reliability and safety. Reliability and safety are both affected by secondary cable overloads, network design deficiencies, and intrinsic asset conditions. An overload occurs when a cable operates above its rated temperature. A network design deficiency is when there are fewer secondary equipment ties than are needed to maintain a network. Intrinsic asset conditions may include the structures environment, cable density and performance. The program's work includes secondary cable, joint, and conduit replacement – including street excavations for laying new conduits.



Specification EO-10308 currently classifies mains into three distinct priorities for program management. These priorities are based on secondary cable and network transformer overloads, low voltage conditions, radially fed customers, confirmed power quality issues, backfeed, and other engineering criteria.

Priority I – The highest probability of an event and most substantial consequences including equipment damage, loss of power, low voltage, overloads, and service interruption to critical customers.

Priority II – This priority includes customer impact and overloads to a lesser degree than Priority I and also includes equipment coordination issues.

Priority III – Minimal impact to customers and the underground secondary grid.

In addition to the above engineering design factors, intrinsic condition analysis and field scope changes may be used to further categorize and advance or regress work. This program replaces secondary cables by and from all three priorities based on funding allocated to this program.

Justification Summary:

Secondary open mains can result in local overloads within a network by shifting the flow of current from nearby in service transformer(s) while increasing load flow from more remote transformers and cables. Overloaded secondary cable sections, whether created by open mains or load increases, require replacement and/or reinforcement to mitigate low voltage conditions, manhole events, equipment coordination problems, and damage due to thermal overload. The company is taking proactive steps to analyze all open mains, determine the impact on the system and adjacent cables in order to avoid causing any loss of life in those cables while the target cable is out of service. This is done through the use of the Priorities previously mentioned and assigning them to each open main and then using them in the assignment of which cables and associated conduits are replaced.

Supplemental Information:

- Alternatives:
  The alternative to implementing the Open Mains program is to cascade cable overloads when they occur. However, this is likely to result in equipment damage and therefore, lower service reliability would be realized.

- Risk of No Action:
  Inaction will significantly impact customer service reliability, which includes extended restoration times and power quality issues. The process of studying each open main and assigning a priority helps ensure that cable is replaced or reinforced to ensure network stability and the ability to meet loading requirements.

- Non-financial Benefits:
  Con Edison's network customers experience the most reliable electric service in the country. Compared to the New York State (excluding Con Edison) average customer interruption rate of over 1000 interruptions per 1000 customers, the Company's network average customer interruption rate in 2016 was approximately 19 per 1000 customers. Thus, the service reliability of network customers is 53 times better than the NY State average. This program is required to ensure that the Company can continue to provide exceptional service to its customers.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis:

Secondary open mains are often caused by mechanical damage and chemical breakdown of the cable insulation from aging, movement, and improper load distribution. This insulation damage can result in arcing and eventually a fault leading to an open main(s). Secondary failures often occur in the winter when salt is distributed to melt the snow and to a lesser extent, in the summer from higher precipitation and loads. Cable replacement and reinforcement is critical to maintaining continuity of service to our network customers and preventing further equipment damage. This program will continue to address any and all capital reinforcements and replacements required to prevent cable failure or overload.

Open Mains	**2019**	**2020**	**2021**	**2022**
Received	4,613	4,613	4,613	4,613
Pending	2,573	2,608	2,136	1,764
Planned Repairs	4,578	5,085	4,985	4,887

- Project Relationships (if applicable):

- Basis for Estimate:
  Estimate is calculated based upon historical data with 1% increase attributed to cable aging.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Forecast 2018**
Labor	38,685	39,080	37,781	42,485		40,354
M&S	20,902	21,598	17,181	19,288		20,248
A/P	17,557	19,991	22,589	29,173		26,215
Other	5,948	11,356	14,137	16,381		16,186
Overheads	56,552	68,392	53,833	54,466		50,641
Total	**139,644**	**160,417**	**145,521**	**161,793**		**153,644**

Future Elements of Expense

EOE	**Budget 2019**	**Request 2020**	**Request 2021**	**Request 2022**	**Request 2023**
Labor	34,729	39,033	41,315	42,291	42,528
M&S	18,144	20,148	19,779	18,818	18,749
A/P	15,480	16,704	16,646	15,584	15,489
Other	19,200	21,602	21,549	21,488	21,452
Overheads	47,744	45,755	44,099	45,230	45,508
Total	**144,495**	**153,000**	**153,000**	**153,000**	**153,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Service Replacements
Project Manager	Various
Hyperion Project Number	PR.20451610, PR.20451611, PR.20456590, PR.20456591, PR.20455748, PR.2ED5011
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Regulatory Mandated

Work Description:
Service cables and conduit are the final connection between our distribution system and our customers. These facilities provide our customers with the electric power they require for their homes and businesses. Over time these services fail based on a number of factors (age, weather, load, etc.) When the failed service's replacement must be deferred or is unsuccessful, due to local field conditions, a temporary service is established to return the customer to service. This program provides funding to remove the temporary service connection and perform a permanent service repair. However, if the existing conduit is unusable due to obstructions or size constraints, the repair will also require the installation of a new service conduit.

The years 2017 and 2018 had winter storms that impacted the system resulting in a high number of weather related customer electric service outages from damaged electric service wires. Once an electric service outage is reported, a temporary repair is initiated when crews are unable to immediately make a permanent repair. Temporary repairs occur either by installation of a bridge on the electric service (where the damaged service leg is cut clear and remaining customer electric load is jumped to the remaining service leg) or a shunt is installed (a temporary cable installed above the ground).

The table below describes the Temporary Services repair plan with additional units to reduce the total number of on-hand temporary services.

Temporary Services	**Year-End Projections - Cable Units With Conduits**				
	2018	**2019**	**2020**	**2021**	**2022**
Starting Backlog	4,075	4,625	6,025	9,255	10,910
Projected Incoming	8,700	8,700	8,700	8,700	8,700
Total Completion	8,150	7,300	5,470	7,045	7,045
Backlog	4,625	6,025	9,255	10,910	12,565

Justification Summary:
This program is mandated by the New York Department of Public Service Commission (PSC).

When a customer has no electric service, or partial service, Con Edison attempts to make a permanent repair. Field conditions often prevent access to the cable(s), requiring a temporary service be installed. Examples of issues preventing access include alternate side of the street parking which prevents access to the source structure, construction or a dumpster over the structure, or situation where the structure is paved over. When access is a problem the customer is provided with a temporary service. Other situations that require the use of a temporary service include the inability to replace the defective cable due to an obstructed service conduit, or the conduit being too small for the new service cable. When the service conduit is unusable, Con Edison is required to excavate the street and install a new conduit. When excavation is required, the municipality requires specific street opening permits, which take time to file and receive from the municipality. This permit process delays permanent restoration so a shunt (temporary service) is provided to the customer to provide immediate restoration of electric service. The Company is obligated to replace a temporary service with a permanent repair within 90 days of the temporary service installation.

Supplemental Information:

- Alternatives:
  The alternative to installing a temporary service would be to utilize an alternate power supply that could include a portable generator or a battery/inverter set. The reliability of these alternate supplies is not as consistent as a temporary service and could subject the customer to further interruptions and thereby reduce customer service and experience through this service replacement.

- Risk of No Action:
  Temporary services left in-service for more than 90 days incur financial penalties.

- Non-financial Benefits:
  The permanent repair of temporary services enhances public safety by removing service shunts. These shunts present both a potential tripping hazard and a hazard from having live electrical cable on the ground within reach of the public.

- Summary of Financial Benefits (if applicable) and Costs:
  This program is a regulatory mandate. Temporary services are repaired within 90 days regardless of cost.

- Technical Evaluation/Analysis:

- Project Relationships (if applicable):
  Emergency Response
  Burnouts or B Tickets – Underground

- Basis for Estimate: Historical unit costs were used.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	13,508	13,022	16,422	20,892		18,982
M&S	3,666	3,212	2,496	2,946		1,929
A/P	12,540	14,438	11,062	15,833		12,447
Other	5,324	5,840	2,271	3,511		15,819
Overheads	26,282	28,409	21,393	23,562		20,007
Total	**61,320**	**64,921**	**53,644**	**66,744**		**69,184**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	13,262	13,640	20,817	18,781	16,462
M&S	3,599	3,364	3,164	2,648	1,673
A/P	12,312	15,123	14,022	14,233	10,795
Other	5,227	6,117	2,879	3,156	13,719
Overheads	25,803	29,756	27,118	21,181	17,351
Total	**60,203**	**68,000**	**68,000**	**60,000**	**60,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Street Lights (Including Conduit)
Program Manager	George Jensen
Hyperion Project Number	PR.20451610, PR.20451611, PR.20456590, PR.20456591, PR.20455748, PR.2ED5011
Status of Project	In Progress
Estimated Start Date	On-going
Estimated Completion Date	On-going
Work Plan Category	Regulatory Mandated

Work Description:
This program addresses the replacement of secondary cable that provides service to Street Lights and associated conduit. Street Lights have become an increasingly important public safety concern for the New York City Department of Transportation (NYCDOT) and Westchester Municipalities. The City and Municipalities who maintain these lights, patrol and collect field complaints from the public to determine which lights are not working. The lights are then tested to determine whether the City/Municipalities or Con Edison has the responsibility for making the repairs.

Justification Summary:
This program is mandated by the New York Department of Public Service Commission (PSC). The Company is obligated to repair 90% of all incoming no current street lights in 90 days during the winter period and 80% of all incoming no current street lights in 45 days during the summer period.

The Company receives work requests from NYCDOT and Municipalities for approximately 8,000 streetlights annually due to apparent burnout of Company service cables. Approximately 5,000 of these jobs require cable replacement.

Here is the forecasted repairs for 2019-2022.

Streetlights Capital	**2019**	**2020**	**2021**	**2022**	**2023**
Received	4,260	4,260	4,260	4,260	4,260
Pending	330	310	300	300	310
Tolled*	350	350	350	350	350
Planned Repairs	3,930	3,920	3,910	3,900	3,900

Tolled* - Jobs that are delayed due to factors outside the Company's control (i.e. DOT, building construction or permitting).

Supplemental Information:

- Alternatives:
  No practical alternative other than allowing the streetlights to remain in their current condition.

- Risk of No Action:
  Streetlight failures need to be identified and permanently repaired as they are a vital part of keeping public areas safe. Con Edison has an obligation to public safety and to address any Con Edison owned equipment problems associated with streetlights as they are identified by the City and Municipalities. We plan to continue to make timely, permanent repairs to our streetlight infrastructure as a commitment to public safety. This ensures that streetlights stay lit and new cable installations lessen the possibility of stray voltage conditions.

- Non-financial Benefits:
  Benefits include continued and improved public safety, increased service reliability, improved customer satisfaction, and improved relationships with Community Boards and the Public Service Commission (PSC).

- Summary of Financial Benefits (if applicable) and Costs:
  Cost estimates are based on performing 5,000 replacements per year at an average cost of $5,150 each – this is based on historical cost for 2016-2017.

- Technical Evaluation/Analysis:
  Some of the stray voltage events associated with metal streetlights that are discovered each year are due to failures of company owned phase conductors or neutral cables. In addition, the Company receives work requests from the NYCDOT and Municipalities for approximately 8,000 streetlights repairs due to an apparent burnout of company service cables. Approximately 5,000 of these jobs require cable replacement.

- Project Relationships (if applicable):
  N/A

- Basis for Estimate:
  Actual completions & receipts are projected based on actual yearly average costs. Funding is increased to account for the higher number of street light service cables due to the recent severe winters and the resulting elevated number of service cables that have failed.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1,107	1,116	1,414	1,146		806
M&S	1,104	933	982	871		756
A/P	11,812	11,119	11,375	18,639		17,671
Other	297	342	627	420		557
Overheads	12,676	11,635	9,211	10,387		9,719
Total	**26,996**	**25,145**	**23,609**	**31,463**		**29,509**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,038	1,209	1,631	737	744
M&S	1,035	1,011	1,133	560	698
A/P	11,076	12,043	13,122	11,987	16,310
Other	279	370	723	270	514
Overheads	11,887	12,602	10,626	6,680	8,970
Total	**25,315**	**27,235**	**27,235**	**20,235**	**27,235**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Targeted Primary DBC Replacement
Program Manager	Kenneth Magnus
Hyperion Project Number	PR.5ED4261, PR.5ED2261
Status of Project	In Progress
Estimated Start Date	2009
Estimated Completion Date	2029
Work Plan Category	Strategic

Work Description:
This is a 20 year program that will replace primary and secondary Direct Buried Cable (DBC) with a higher quality jacketed DBC to improve the reliability of the supply to Underground Residential Distribution (URD) customers. The URD developments are entered into a ranking system which takes into account the age of the cable within the development and also the interruption rate. Once each development has been ranked, a strategic reinforcement approach will be implemented.

Justification Summary:
The chart below shows the number of URD customers each year in Westchester and Staten Island that experienced a service interruption due to problems with DBC. On average, it takes 20% longer to locate and repair a fault when it occurs on DBC than it does to repair a fault that occurs on the same cable installed in a conduit. Undertaking a more aggressive Targeted URD replacement program for both primary/secondary sections and services will reduce the number of DBC outages on the URD system (SAIFI) and also will reduce annual repair expenses.

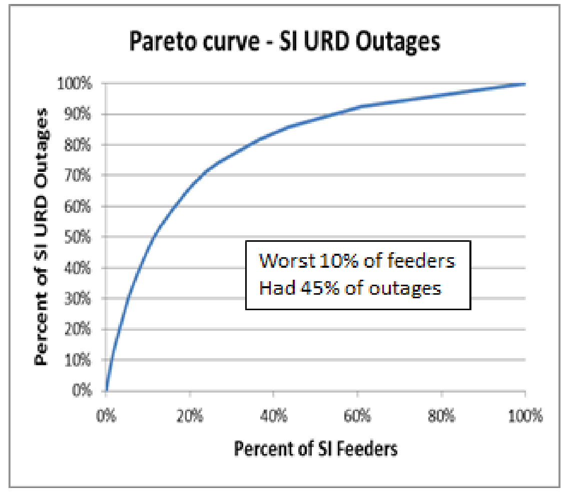
	2013	**2014**	**2015**	**2016**	**2017**
URD Outages	3736	4328	7952	6211	8317

Asset Management has completed an asset class model for URD cable that calculates both the health of individual URD sections as well as the total replacement rate needed to maintain a targeted failure rate. The asset class model unidentified within specific regions where URD was most prone to failure as well as types of URD cable that would fail more often. In particular, the Staten Island Region had a higher failure rate than the Bronx/Westchester Region. This is because Staten Island has a high population of pre-1980 XLPE cable. This cable type has a high failure rate in comparison to other URD cable types. In addition, the asset class model was able to focus in on 10 feeders in Staten Island which accounted for over 50% of the total failures.

First, identify and rank the worst feeders:

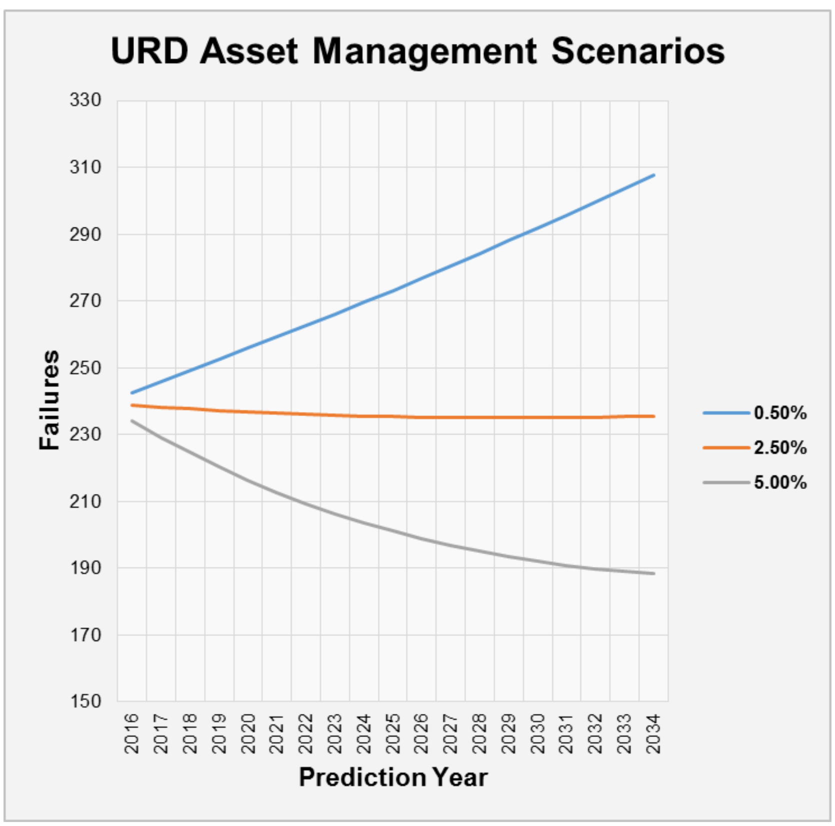
- Rank by Feeder

Rank by Feeder	Outages*	10-yr. CI
– S5R15	42	3,086
– SM4R54	34	2,041
– S5R11	27	2,019
– S4R66	26	2,465
– S2R13	25	1,362
– SM3R30	25	1,266
– SL4R54	20	1,116
– SL4R74	18	1,327
– S5R20	18	918
– S4R64	17	863



Then, within the worst feeders, find the worst half-loops.

Based on that model, in order to maintain the current failure rate, 25 URD sections need to be replaced every year (2.5% of the total population per the chart below).



In addition, the Asset Management Group also did research into partial discharge testing. Under this plan, the worst URD sections would be tested before replacement.

<u>Supplemental Information</u>:

- <u>Alternatives</u>:
    - URD Cable Rejuvenation
    - Rehabilitation
    - Partial Discharge
    - Fault Indicator Program

  These programs while valuable will not remedy areas where cable has repeatedly faulted due to the number of buried splices and condition of the cable.

- <u>Risk of No Action</u>:
  Continued customer interruptions due to URD cable failure and greater emergency expense for URD repairs since DBC repair requires digging. Leaving failing cable in place may lead to multiple outages for the same customers resulting in an increase in complaints and frustration.

- <u>Non-financial Benefits</u>:
  Improved system performance by reducing the amount of customer interruptions. This will increase overall reliability, resulting in a reduction in System Average Interruption Frequency Index.

- <u>Summary of Financial Benefits (if applicable) and Costs</u>:
  Program costs are anticipated at approximately $4 million per year and growing.

- <u>Technical Evaluation/Analysis</u>:
  When this program was conceived, approximately 60% of all URD customer interruptions were due to insulation breakdown of DBC primary and secondary cables. These interruptions resulted in an average of 55 outages/year and 67 outages/year for Westchester and Staten Island respectively. Targeted installation of URD cable-in-conduit and direct buried systems for both primary/secondary sections and services will reduce the amount of DBC on the system thereby reducing URD customer outage frequency (SAIFI), which brings a number of associated benefits to the customers (such as an enhanced customer experience) and Company (such as reduced emergency response costs).

  Asset Management has completed the asset class model for the URD System. This asset class model suggests various replacement strategies. Some possible renewal programs include:
    - Replace only the sections that have failed 4 times,
    - Inject all sections that can be injected and replace the rest
    - Partial discharge test, repair some (typically 1/3) and replace those that need it (typically another 1/3)
    - Replace all sections with testing. Each of these options will have a different cost associated with it, as well as differing impacts on customer outages, etc.

- <u>Project Relationships (if applicable)</u>:
  None

- <u>Basis for Estimate</u>: The estimates for this program are based on historical unit costs to replace direct buried cable.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	207	201	813	923		935
M&S	270	140	348	572		447
A/P	664	553	1,222	2,361		1,301
Other	1	15	22	4		14
Overheads	864	696	1,490	1,867		1,339
Total	**2,006**	**1,605**	**3,895**	**5,727**		**4,035**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	360	698	1,388	1,610	1,655
M&S	932	1,974	3,283	3,951	3,905
A/P	1,385	3,445	4,186	3,148	3,157
Other	463	1,018	1,638	1,807	1,784
Overheads	1,506	2,864	3,505	3,482	3,500
Total	**4,647**	**10,000**	**14,000**	**14,000**	**14,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Transformer Installation
Project Manager	Various
Hyperion Project Number	PR.20451610, PR.20451611, PR.20456590, PR.20456591, PR.20455748, PR.2ED5011
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
Due to public safety concerns, we have instituted various programs to identify equipment that could potentially fail. This includes a more aggressive underground transformer inspection program which includes testing for dissolved gas in oil for all units. We have also started installing remote monitoring equipment on transformers to provide real time pressure and temperature readings. Replacing failed transformer units and those that require replacement as a result of defects found during inspection is a critical function for ensuring the integrity of the network system. As a result of this increased monitoring, we have experienced an increased number of units needing replacement in order to maintain our system reliability.

This program is to replace electrical distribution equipment (primarily underground network transformers and their associated, cable, conduit, and structures) that is found to be defective. These defective equipment replacements account for approximately 55% of transformer installations (the remaining 45% include load relief and new business). These components are identified for removal based on equipment condition determined from visual inspection, dissolved gas in oil analysis, and remote sensors which report pressure, temperature and oil level. Removal prioritization is based on risk of failure. Transformers with confirmed low levels of oil or with oil or pressure leaks are given the highest priority for removal from service.

Analyses of Pressure, Temperature and Oil sensor data have dramatically reduced the number of in service transformer failures, there were 147 failures in 2005 and in the last 5 years the average failure rate is 21 transformers per year. These reductions are directly correlated with the results of our failure mitigation programs. In the last 5 years, we have preemptively removed approximately 933 units that exhibited symptoms to potentially fail in-service through the use of engineering programs in addition to field removals.

Justification Summary:
Replacing failed transformer units and those that require replacement as a result of defects found during inspection is a critical function for ensuring public safety and system reliability. Public safety has already been improved by the installation of pressure, temperature, and oil level sensors which provide information to our remote monitoring system. These installations have resulted in reductions in transformer ruptures by allowing us to identify defective transformers and remove them from service prior to failure.

The reliability of the network system is dependent on the integrity of our network transformers. Transformer failures can contribute to the loss of multiple feeders in the same network, particularly during periods of high load which can result in local area voltage problems and customer outages.

Supplemental Information:

- Alternatives: There is no practical alternative to replacing failed distribution transformers as they are required to maintain electric service to our customers. The alternative to replacing transformers identified as defective with the potential to fail is to continue to operate the equipment and risk a catastrophic failure. This alternative would jeopardize public safety and system reliability and is not viable.

- Risk of No Action: Failing to replace transformers would jeopardize public safety and system reliability.

- Non-financial Benefits: Transformer replacements improve public safety and system reliability by removing defective transformer. In addition to reducing equipment failures, the number of unplanned feeder outages is also reduced, since every transformer failure results in de-energization of the entire feeder that supplies it.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: Defective transformers are classified as "Banks Off" when they are no longer supplying the electrical secondary grid but before they are replaced. Some Banks Off require complete equipment replacement, while others may involve a repair to either the transformer or network protector. The following table summarizes the plan to reduce the number of Banks Off on the system.

Banks Off System	**2019**	**2020**	**2021**	**2022**
Received	2,234	2,234	2,234	2,234
Pending	356	409	505	644
Planned Repairs	2,251	2,181	2,138	2,095

- Project Relationships (if applicable): Transformer Purchase Program – The Transformer purchase program provides the funding for the purchase of the transformer installed under this program.

- Basis for Estimate: The basis for the cost estimates is the historical program unit cost for transformer installation.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	8,518	6,262	6,428	8,254		8,422
M&S	1,873	1,219	1,188	1,247		5,820
A/P	2,656	1,841	2,237	2,211		204
Other	14,204	14,965	10,959	11,704		12,423
Overheads	37,826	34,827	29,785	34,034		38,346
Total	**8,518**	**6,262**	**6,428**	**8,254**		**8,422**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	9,813	10,862	10,812	11,197	11,340
M&S	7,904	6,453	7,746	8,704	8,322
A/P	1,738	1,256	1,432	1,315	5,751
Other	2,465	1,897	2,696	2,332	202
Overheads	13,181	15,422	13,205	12,342	12,275
Total	**35,101**	**35,890**	**35,890**	**35,890**	**37,890**

X	Capital
	O&M

2019 Central Operations/System & Transmission Operations

Project/Program Title	Transmission Failures - Other
Project Manager	Various
Hyperion Project Number	PR.21556402
Status of Project	Engineering
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Operationally Required

Work Description:
The Transmission Failures – Other Program provides funds for the replacement of failed equipment associated with transmission feeders. The work scope of this program will include, but is not limited to, the replacement of failed cable terminations, riser cable sections or other transmission feeder equipment located inside substations.

Justification Summary:
The Transmission Failures - Other Program establishes capital funding to address transmission feeder equipment replacements inside a substation. While funding for some transmission feeder repairs is provided in the O&M program, the cost of repairs requiring the complete replacement of a new cable termination or riser cable section are covered through this capital program.

For transmission feeders, pothead replacement would be recommended based on a technical evaluation performed by Transmission Engineering. Potential conditions necessitating replacement includes the following:

- Physical inspection showing any visible damage to the cable insulation, stress cone, or cable shielding inside the pothead including broken or missing tapes, ridges or insulation distortion, or electrical discharges.
- Dielectric fluid or material analysis showing contamination such as high moisture content or reduced insulation strength.
- Broken or ruptured porcelain or riser pipes leading to a dielectric fluid leak that cannot be repaired.

The continuation of this program will help maintain underground Transmission System reliability. The scope and funding for this program was previously carried under the "Failed Equipment Program" for Substation Operations.

Supplemental Information:

- Alternatives: The alternative to replacing failed cable terminations and associated equipment is to repair them. For some types, spare components are no longer available requiring replacement with new style terminations. Additionally, higher electrical stresses in the terminations make them more vulnerable to failure if damage within the insulation is not visible during repairs.

- Risk of No Action: The risk of no action can jeopardize the reliability of the Transmission System. If multiple failures were to occur during a high load period or while other critical facilities are out of service, load shedding and large-scale customer outages can result. Emergency mobilization and fault locating costs are also avoided by addressing the reliability issues proactively. Removing the suspect configurations and enhancing feeder reliability also helps avoid significant job cancellation costs for working groups throughout the Company due to the far-reaching effects on scheduled transmission facility work when a transmission pothead fails.

- Non-financial Benefits: Transmission feeder components in substations, such as cable terminations or auxiliary pressurization sources, make up essential elements of feeder availability. In order to maintain reliability, failed components must be replaced so that feeders can be restored as quickly as possible. This program will facilitate the restoration of transmission feeders following failures of components that are inside substations.

- Summary of Financial Benefits (if applicable) and Costs: Not applicable.

- Technical Evaluation/Analysis: Please see Alternatives above.

- Project Relationships (if applicable): None.

- Basis for Estimate: Historical spending levels were used as a basis for funding levels in this program.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	56	127		-
M&S	-	-	-	12		-
A/P	-	-	18	-		-
Other	-	-	21	12		-
Overheads	-	-	66	102		-
Total	**-**	**-**	**161**	**253**		**-**

Future Elements of Expense:

EOE	2019	2020	2021	2022	2023
Labor	200	200	200	200	200
M&S	250	250	250	250	250
A/P	150	150	150	150	150
Other	100	100	100	100	100
Overheads	262	276	300	300	300
Total	**962**	**976**	**1,000**	**1,000**	**1,000**

X	Capital
	O&M

2019 Central Operations/System & Transmission Operations

Project/Program Title	Transmission Feeder Failures
Project Manager	Mark Bauer
Hyperion Project Number	PR.22679436
Status of Project	Engineering
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Operationally Required

Work Description:
The Transmission Feeder Failures Program provides funds for the repair of underground transmission feeders when the repair scope of work, as determined by Transmission Engineering, requires a complete cable section replacement between manhole structures and splicing of new joints.

Justification Summary:
The Transmission Feeder Failures Program establishes capital funding to address major transmission repairs. While funding for some transmission feeder repairs is provided in the O&M program, the cost of extensive replacements requiring the installation of a new cable section and joints are covered through this capital program.

For a high-pressure pipe-type cable transmission feeder, a complete cable section replacement would be recommended based on a technical evaluation performed by Transmission Engineering. This takes into consideration the following:

1) Evaluation to determine if external contaminants entered the dielectric fluid system caused by a water main/water service leak which over time can cause a cable failure.
2) Evaluation of operational history of the cable section (multiple failures in section) and original cable manufacturer.
3) Physical inspection of the fault and companion conductors for evidence of thermal- mechanical damage or other observed abnormalities that will likely result in subsequent failures in the section if not addressed.

The continuation of this program will maintain underground Transmission System reliability.

Supplemental Information:

- Alternatives: The alternative to a cable section replacement is to remove the localized area of damaged cable and install a short section of cable and two buried joints at the fault location. If this alternative is exercised and water and/or other contaminants have entered the pipe, the integrity of the dielectric fluid system has been compromised and subsequent failures may occur due to contamination of the dielectric fluid system and paper insulating tapes of the cable. With regards to thermal-mechanical damage, or other abnormalities observed during inspection of the fault, the alternative again exists to remove only the damaged cable and install two buried joints and a short section of cable. There is the possibility that similar damage on the cable may exist within other areas of cable section not readily seen at the localized repair location. A subsequent failure may then occur in the same cable section at a later date. For example, a failure occurred in July 2014 on 345kV Feeder 71 between manhole structures M7369 and M7368 located in Yonkers. The cable fault was inspected by engineering representatives and the repair scope was to replace the cable section between the manhole structures. While the cable was being removed from the pipe, engineering representatives on location observed cable insulation damage approximately 250 feet away from the original fault location, which would have resulted in a future failure.

- Risk of No Action: The risk of no action is an adverse impact on Transmission System reliability. If multiple failures were to occur during a high load period or while other critical facilities are out of service, load shedding and large-scale customer outages can result. Emergency mobilization and fault locating costs are also avoided by addressing the reliability issues proactively. Removing the suspect configurations and enhancing feeder reliability also helps avoid significant job cancellation costs for working groups throughout the Company due to the effects on scheduled transmission facility work when a transmission feeder fails.

- Non-financial Benefits: The availability of transmission and sub-transmission feeders is an important part of maintaining the reliability of the transmission system. This program will provide the funding to facilitate the quickest possible return to service for transmission feeders that have failed and/or require a cable section replacement.

- Summary of Financial Benefits (if applicable) and Costs: Not applicable.

- Technical Evaluation/Analysis: Please see Alternatives above.

- Project Relationships (if applicable): None.

- Basis for Estimate:

  The basis for the $10M annual budget request for is two 345kV failures occurring annually, each requiring a complete cable section replacement and splicing of joints at a unit budgetary cost of $5M per incident.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	3,894	2,065	2,201	4,344		4,500
M&S	3,694	3,426	347	2,707		2,800
A/P	2,241	1,865	1,757	6,881		6,500
Other	207	142	238	2,887		2,700
Overheads	6,095	4,423	2,370	5,846		6,000
Total	**16,131**	**11,921**	**6,913**	**22,665**		**22,500**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	2,582	3,343	3,298	3,289	3,327
M&S	1,060	1,060	1,060	1,060	1,060
A/P	1,982	2,900	2,900	3,000	3,000
Other	2.014	1,600	1,600	1,600	1,600
Overheads	1,781	1,097	1,142	1,051	1,013
Total	**9,419**	**10,000**	**10,000**	**10,000**	**10,000**

Exhibit __(EIOP-7)

T&D Equipment Purchase

Electric T&D		Year Total			
Equipment Purchases		Current Budget			
		Total Dollars ($000)			
		RY1	RY2	RY3	3 Yr. Total
Equipment Purchases					
Organization	**White Paper**				
Distribution	Meter Purchases	5,500	6,000	8,000	19,500
Distribution	Sarnoff Equipment	5,000	5,000	5,000	15,000
Distribution	Transformer Purchases	116,000	121,000	126,000	363,000
TOTAL ELECTRIC					
	Total Equipment Purchases	**126,500**	**132,000**	**139,000**	**397,500**

Schedule 1: T&D Equipment Purchases Capital Program and Project Summary

Infrastructure Investment Panel				
O&M Program Changes				
EIOP - Risk Reduction				
($000)				
		RY1 Program Change	**RY2 Program Change**	**RY3 Program Change**
Risk Reduction				
Organization	**Program Change**			
Distribution	Meters and Other Customer Equipment*	(333)	(860)	(1,087)
TOTAL ELECTRIC				
	Grand Total	**(333)**	**(860)**	**(1,087)**

Schedule 2: T&D Equipment Purchases O&M program Change Summary

**AMI Electric Operations White Paper is associated with Meters and Other Customer Equipment*

Schedule 3:

T&D Equipment Purchases White Papers

Equipment Purchases

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Meter Purchase
Project Manager	Charles Feldman
Hyperion Project Number	PR.2ED1213
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
Provides for the purchase of electric revenue meters and associated metering equipment for revenue collection as required by PSC regulations. The purchases include electric meters and associated metering equipment such as revenue grade instrument transformers.

Units per Year: Approximately 167,000 electric meters and associated metering equipment are required.

Mandatory: Approved electric revenue metering equipment is required by PSC regulations.

High-level schedule: This is an ongoing activity where the metering equipment is purchased based on requests and expected needs.

Justification Summary:
This is required to support new businesses and customer upgrades.

Supplemental Information:
Additional information to reinforce the justification.

- Alternatives:

There are no acceptable alternatives to the use of PSC approved metering devices as specified in PSC Part 92 for billing customers.

Meters provide the means to accurately record customer demand, implement time of day rates, demand response and energy efficiency programs and comply with regulatory metering programs such as reactive power. The last step in bringing new customers on line with electric service is to install the meter. Without meters, many new customers would be delayed or tied in unmetered. New tariffs would have to be developed to support flat rate un-metered billing.

- Risk of No Action:

Without meters and the existing tariffs in place, customer usage would need to be estimated which is not reliable and subject to dispute.
Summary of Benefits (financial and non-financial):
Provides for accurate registration of energy consumption. Accurate billing supports customer satisfaction.

Basis for Estimate: Historical data.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	2,582	2,369	2,303	2,723		2,103
M&S	5,640	7,477	7,487	4,548		1,095
A/P	(12)	(11)	(10)			-
Other	(107)	(238)	(293)	(226)		-
Overheads	1,279	1,572	1,207	1,244		802
Total	**9,382**	**11,169**	**10,694**	**8,289**		**4,000**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	876	990	1,061	1,417	1,773
M&S	3,362	3,670	4,034	5,379	6,724
A/P	-	-	-	-	-
Other	299	326	358	478	597
Overheads	461	514	547	726	906
Total	**5,000**	**5,500**	**6,000**	**8,000**	**10,000**

X	Capital
	O&M

2020– Electric Operation

Project/Program Title	Sarnoff Equipment Purchase
Project Manager	James Leary
Hyperion Project Number	PR.23443502
Status of Project	In Progress
Estimated Start Date	2018
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
In accordance with the PSC's "Order Establishing Rates for Electric Service," issued March 25, 2008 in Case 08-E-0539, Con Edison is to perform 12 underground system scans in underground distribution areas of New York City using mobile contact voltage detection technology. In accordance with the PSC's "Order Adopting Changes to Electric Safety Standards," issued December 15, 2008 in Case 04-M-0159, the 12 underground system scans must be performed within each rate year (April 1st to March 31st). In addition, Con Edison is to perform one underground system scan using mobile contact voltage detection technology annually in New Rochelle, Yonkers, and White Plains, as ordered in Case 10-E-0271. Con Edison also performs an underground system scan in Mount Vernon.

This capital program will fund the procurement of new scanning sensors and associated software as well as the new vehicles that they will be mounted to.

Justification Summary:
The Company is required to perform mobile voltage scans pursuant to the PSC Safety Order(s) previously mentioned.

Supplemental Information:

- Alternatives: Perform manual testing for voltage on the company facilities in the mobile scanning area. Manual testing is limited to the external surfaces that are touched with the test device, so the energized objects found would be limited to those surfaces tested. Whereas the mobile device detects an electrical field so any energized object within the detectable range will be found. Manual testing is simply less thorough. It is also required by regulation to perform the mobile scans.

- Risk of No Action: This is a regular inspection and maintenance program that catches and resolves minor issues before they have the chance to become hazardous or cause outages. If this work is not performed, then any problems not identified may present a public safety or reliability risk. In addition failing to perform this work would be a failure to comply with the NY PSC Public Safety Order.

- Non-financial Benefits: The periodic inspections performed under this program improve both public safety and reliability.
- Summary of Financial Benefits (if applicable) and Costs: See section on basis for estimate.
- Technical Evaluation/Analysis: See justification section.
- Project Relationships (if applicable): Mobile Voltage Scanning Program (O&M) –this is the O&M program to operate this equipment and provide associated services.
- Basis for Estimate: Estimates Received from vendor.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	4,565	4,565	4,565	4,565	4,565
A/P	-	-	-	-	-
Other	374	374	374	374	374
Overheads	62	62	62	62	62
Total	**5,000**	**5,000**	**5,000**	**5,000**	**5,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Transformer Purchase
Project Manager	Jane Shin
Hyperion Project Number	PR.2ED1002, PR.9ED8031
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program will fund distribution system equipment purchases under the ED2 capital budget used to purchase new and reconditioned capital electrical distribution equipment. This equipment includes underground network transformers, overhead transformers, padmount transformers (including mini-pads), capacitor banks, emergency generators, and network protectors to support distribution system relief, reliability, emergency, and load growth programs.

This funding is needed to provide Electric Operations Construction and Energy Services with electrical distribution equipment in order to complete active and planned burnout, new business, and system relief and reinforcement projects. Additional details are provided in the related white papers for transformer installation and load relief capital installations.

We will continue to institute and expand the various failure mitigation programs to identify the electrical distribution equipment on our system for which removal is most urgent. These programs are designed to proactively inspect our field equipment, replace equipment that exhibits warning signs of potential failure, ensure public safety, and maintain system reliability.

Analyses of Pressure Temperature Oil sensor data have dramatically reduced the number of in service transformer failures, there were 147 failures in 2005 and in the last 5 years the average failure rate is 21 transformers per year. These reductions are directly correlated with the results of our failure mitigation programs. In the last 5 years, we have preemptively removed approximately 933 units that exhibited symptoms to potentially fail in-service through the use of engineering programs in addition to field removals.

Additionally, Con Edison has been working with network transformer vendors to develop dry type submersible underground distribution transformers. The advantage of such units is that they do not contain dielectric fluid so there are no concerns with leaks or fire. These are potentially desirable features for locations with high pedestrian traffic and indoor installations. Prototypes have been reviewed and a limited population is undergoing field trial.

Justification Summary:
Without the required funding, we would be unable to purchase electrical distribution equipment as needed. Lack of installed transformer capacity in the same network especially during high load periods can result in system degradation and reliability issues including local area voltage problems and customer outages. In addition to impacting the distribution system reliability and customer service, there is a

significant public safety concern if we are unable to proactively replace defective transformers in a timely manner.

Supplemental Information:

- Alternatives: Distribution Equipment is required to maintain electric service to our customers and system reliability. Therefore, there is no viable alternative to purchasing transformers at this time.

- Risk of No Action: Reduction in funding could impact availability of equipment for emergency replacement, new business work, or load relief. This would adversely impact system safety and reliability.

- Non-financial Benefits: Replacing old degraded equipment (particularly equipment at elevated risk of failure) reduces the probability and frequency of equipment failures. This improves reliability by reducing the number of feeders that trip out (open). In addition, the ability to replace equipment reduces the risk of violent failure, which decreases the risks of injury to the public and to property.

  The Company has made substantial progress and continues to work to establish additional suppliers for our major distribution equipment in order to promote competition and supplier diversity. The increased competition helps to reduce equipment costs, while the increased supplier diversity expands sourcing options and equipment availability. In addition to the diversification of vendors, Distribution Engineering has worked to develop quality metrics to track each vendor's product quality and on-time-delivery performance. These metrics have been incorporated into Purchasing's distribution equipment bid process.

  The Company also continues to recondition equipment removed from service. These efforts help to reduce raw materials entering the waste stream and contribute to lower the total cost of equipment purchases for the company.

- Summary of Financial Benefits (if applicable) and Costs: The approximate allocation of the ED2 budget is as follows:
    - Underground Network Transformers……………………….……45%
    - Network Protectors…………………….……….…….……….…35%
    - Non-Network (Overhead/Padmount) Transformers……….....10%
    - Other (Shunt Reactors, Capacitors, etc.)……………….……10%

  There has been a recent increase in transformer and network protector purchases to support storm hardening initiatives, including upgrading of 480V network protectors to submersible designs and replacement of non-submersible 125/216V network transformers and protectors with submersible equipment. Through 2016, this equipment has been included in storm hardening funding.

- Technical Evaluation/Analysis: The purchasing process incorporates a forecasting model to predict the need for transformers based on historical usage. This model is run on a monthly basis for the purchase of equipment used to maintain electric service and maintain system reliability. The model includes variables such as historical usage, forecasted usage, current inventory levels, equipment on-order, and lead times. The orders are generally optimized to minimize cost while ensuring high levels of equipment availability. In addition, data analysis and trending is conducted on usage, inventory levels, and other supply chain parameters to help reduce costs and guide program spend in an effective and optimal manner.

- Project Relationships (if applicable): Grounding Transformer, Overhead Transformer Relief, Shunt Reactor

- Basis for Estimate: The estimates are projected based on the forecast described above in the Technical Evaluation/Analysis section.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	4,083	4,169	4,247	4,133		4,276
M&S	134,822	131,773	149,009	95,586		88,964
A/P	1,059	1,079	429	688		2,710
Other	(1,762)	(1,397)	(141)	(17)		242
Overheads	8,303	7,685	6,483	4,596		3,909
Total	**146,505**	**143,309**	**160,027**	**104,986**		**100,101**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	4,681	3,698	4,825	4,237	4,113
M&S	77,147	83,957	88,766	91,913	91,715
A/P	859	859	74	859	859
Other	6,928	7,527	7,888	8,232	8,214
Overheads	23,885	19,959	19,447	20,759	21,099
Total	**113,500**	**116,000**	**121,000**	**126,000**	**126,000**

Schedule 4

T&D O&M White Paper

Equipment Purchases

	Capital
X	O&M

2020 – Electric Operations

Project/Program Title	Advanced Metering Infrastructure (AMI)
Project Manager	Thomas Magee
Project Number	21125229 (L1)
Status of Project	Approved
Estimated Start Date	2/2015
Estimated Completion Date	7/2022
Work Plan Category	Strategic Enhancements

Work Description:
Con Edison is amidst deployment of Advanced Metering Infrastructure (AMI) across its service territory from 2016 - 2022. The scope of work for this project includes the following:

1. Building the AMI IT platform and developing the system interfaces between the AMI IT platform and legacy applications
2. Installing the AMI communications network for territory-wide coverage
3. Installing approximately 3.6 million electric smart meters, retrofitting 1 million gas meters with AMI modules and replacing approximately 180,000 tin case gas meters that cannot be upgraded with a new meter and AMI module

Cost reductions to the Electric Operations organization are in the form of labor and non-labor operation and maintenance (O&M) expenses due to efficiencies gained through the implementation of AMI. The O&M reductions for Electric Operations take into consideration the following:

- Distribution Transformers
    - The Company will realize savings in electric distribution transformer O&M, as AMI will improve with the Company's ability to monitor the load on the system (i.e., aggregating the meters that are served by a single transformer). Distribution transformers most often fail due to overloading. AMI will provide the ability to monitor the loading of these transformers more precisely and through engineering analysis of enhanced AMI data, the Company expects to identify overloaded transformers and avoid failures before they occur. Avoiding failures will prevent costly emergency replacement and site cleanup after a failure event. Proactive analysis of transformer loading will also help preserve the life of the asset.
    - This reduction takes into consideration the annual number of transformers that fail due to overloading, the cost incurred to replace the transformers after failure, and an expected percentage of failures that would be avoided as a result of effective load monitoring due to AMI.

- Outage Management
  - The AMI system will improve outage identification and restoration efforts which will benefit customers as well as provide for cost savings. The outage management benefits realized through the deployment of an AMI system include the following:
    - The Company responds to a significant number of outage reports per year that are determined to be "false outages." These "false outages" are not associated with electric service provided to the premise and instead, are the result of customer side electrical problems that require the services of an electrician to resolve. Currently, the Company must dispatch personnel to respond to these outage reports. Following the implementation of AMI, office personnel can determine power status at the meter and avoid a field visit.
    - In addition to false outages, the Company responds to high voltage, low voltage, and flicker claims. As a result of improved monitoring and measurement capabilities, real power quality problems may often be identified before a customer experiences an issue. Many of these calls will be eliminated through analysis of AMI meter data.
    - By reducing the incidence of false outage and power quality items noted above, affected crews can respond more quickly to site safety issues. This results in a reduction of site safety expenses.
    - More effectively managed outages are expected to improve CAIDI (Customer Average Interruption Duration Index) performance. As a result of AMI deployment, the ability to characterize and respond to outages quicker results in increased revenue due to shorter outages.

- Interval Metering
  - Interval metering is used to support the Company's Mandatory Hourly Pricing Program (MHP). This program requires electric customers incurring 30-minute demand (in 15-minute rolling blocks) of 500 kW or more to be billed on the hourly price rate. For several years the NY PSC has indicated the demand threshold for MHP will be reduced to 300 kW, requiring the installation of new meters for an additional group of customers. The costs associated with installing and maintaining interval metering includes monthly communication costs and corresponding changes to MV-90 to receive and manage the meter data. All of these costs will be avoided by replacing interval meters with new AMI meters and integrating these meters into the new meter data management system (MDMS).
  - The Interval Metering benefit is in part attributable to the elimination of communications costs associated with interval meters. It is also attributable to reduced labor costs associated with manual meter reads when communication lines malfunction.

Justification Summary:

The Company believes that the AMI Project will enhance the customer experience by providing information that will enable customers to better manage their energy usage, control costs and help the environment, while allowing the Company to provide improved services that better meet customer expectations in the 21st century. The AMI Project will result in operational efficiencies, including enhanced outage management, a reduction in manual meter reading costs and the number of estimated bills, and remote customer service activation. The AMI project will also support the PSC's Reforming the Energy Vision (REV) initiative to build a clean and resilient energy system for all New Yorkers. The Company is proposing a full scale AMI deployment as the Company believes that the full implementation of AMI is foundational to facilitating enhanced delivery of various customer programs and maximizing customer and Company benefits.

Supplemental Information:

- Alternatives: Con Edison has determined that a full scale AMI implementation best meets our customers' current and future needs, facilitates wide scale demand response program participation, and will be the single most effective means of enabling the energy vision and marketplace envisioned in the Commission's REV initiative. The Company evaluated multiple alternatives to a fully enabled AMI rollout and determined that there are a number of benefits that would not be realized by a partial or non AMI deployment; notably, Con Edison would be unable to meet a number of REV objectives in a cost effective manner or create a cyber-secure communication infrastructure to support the current and future functionality that will be realized by AMI.

  Additional benefits that would not be realized without AMI include: inability to provide real time two-way communication of granular metering data required for customers to make knowledgeable consumption choices, as well as provide the Company with the ability to leverage this detailed information for outage detection, conservation voltage optimization, and better understand the loading of the entire distribution system to optimize system planning and the associated capital spend; with no AMI deployment, the business would stay as it is and not realize operational efficiencies, including enhanced outage management, a reduction in manual meter reading costs and the number of estimated bills, and remote customer service activation.

- Risk of No Action or Delayed Action: There would be a delay in realizing the environmental, customer and company benefits. No action in the near term could mean capital investments in other programs within the distribution network (e.g., transformer upgrades) that could have been avoided or minimized assuming AMI will be implemented in the future. In addition, the bids received from the AMI vendors today are competitive, and there would be a risk of higher costs if the Company chooses to postpone AMI implementation. A risk of no action could result in Con Edison not fully advancing the REV policy objectives. The prevalence of AMI at other utilities may also lead to a failure to meet evolving customer expectations.

- Non-financial Benefits: Customer focused benefits include reduced estimated bills, not having to make appointments for meter reads, a number of environmental benefits and improved outage response. Additionally, AMI may reduce the risk of outages in the event of an emergency with the ability to remotely operate meter service switches through the AMI wireless communications network to enable remote load shedding to maintain grid stability.

- Summary of Financial Benefits (if applicable) and Costs: Major cost savings and cost reduction benefits due to full AMI Implementation have an impact of $2,706 million NPV over the 20-year evaluation period, which include but are not limited to:
  - Estimated benefits from a system perspective in relation to outage management (reduced 'truck rolls' due to more detailed and nested outage data from smart meters, better understanding of mutual aid needs, reduced site safety costs, etc.)
  - System retirement benefits (avoided costs from AMR deployment, ADAMS replacement and associated O&M costs for the existing MDMS)
  - Communications to interval electric and gas meters incur monthly costs (Manual trips for unsuccessful communications). These costs will be eliminated when AMI supports interval data transfers.
  - The Mandatory Hourly Pricing (MHP) program requires electric customers incurring 30-minute demand (in 15-minute rolling blocks) of 500 kW or more to be billed on the hourly

price rate. For several years, the NY PSC has indicated the demand threshold for MHP will be reduced to 300 kW. This will require all new meters for those accounts, communications for those meters, and corresponding changes to MV-90 to receive and manage the meter data. All those costs will be avoided by deploying new AMI meters and integrating these meters into the new MDMS.

- The Company will realize savings in electric distribution transformer operations, which will improve with the Company's capability of monitoring the load on the system (i.e., aggregating the meters that are served by a single transformer). Non-network distribution transformers most often fail due to overloading. AMI provides the ability to monitor the loading of these transformers more precisely. Through engineering analysis resulting from the enhanced AMI data, some failures may be avoided. In avoiding these failures, costly emergency replacement and cleanup processes are also avoided, and the transformer asset itself may be preserved.
- With AMI, outages can be more quickly identified and characterized. Subsequently, outage restoration activities can be better monitored with nested outages being more readily identified and addressed. Correspondingly, false outages and other power problems can be remotely validated so unnecessary truck rolls can be avoided. Lastly, with more efficient outage management, work crews can be more quickly dispatched to other issues resulting in less site safety costs as well as an overall reduction in the CAIDI metric.

- Technical Evaluation/Analysis: Please refer to the AMI Business Plan filed on November 16th 2015 for details on the technical evaluation and analysis.

- Project Relationships (if applicable):
  - The AMI system will support the Distributed System Platform, envisioned by REV. AMI will facilitate Distributed Generation integration and other REV initiatives.
  - The network will support various SCADA initiatives including:
    - Control of Network Protector (NWP) switches
      - The AMI network will be capable of supporting future Smart City initiatives such as street light control

- Basis for Implementation Estimate: The basis for the Electric Operations O&M reductions took into consideration AMI deployment facets that would impact the Company. This includes labor and non-labor cost reductions as a direct reduction of AMI deployment schedules.
  - Interval Metering: Cost avoidance and cost savings in relation to: Annual telecom costs for interval meters, benefits associated with avoided manual interval meter data retrieval, annual O&M for MHP meters, and MV-90 costs avoided by the capability of the new MDMS of the AMI deployment.
  - Distribution Transformers: Cost avoidance and cost savings in relation to: Annual number of distribution transformer failures due to overload and expected percentage of failures avoided through effective load monitoring with AMI. These estimates take into consideration the average cost to replace a failed transformer after failure, average cost to replace a transformer as scheduled maintenance, and the average cost of replacing a transformer.
  - Outage Management: Cost avoidance and cost savings in relation to: False outage calls to dispatches, low-voltage, high-voltage, and flicker calls to dispatches, site safety costs anticipated with better outage data, and increased revenue due to shorter outages with AMI information.

Annual Funding Levels ($000)*:

O&M

Emergency Response

Incremental Change due to this project to the Emergency Response program
Future Elements of Expense

EOE	Request 2020	Request 2021	Request 2022
Labor	(467)	(1,140)	(1,513)
M&S	-	-	-
A/P	-	-	-
Other	-	-	-
Total	**(467)**	**(1,140)**	**(1,513)**

Historical Elements of Expense total Emergency Response program

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Actual 2018
Labor	88,491	100,222	93,232	92,718	103,378	105,751
M&S	2,900	4,865	5,191	3,865	5,877	4,241
A/P	11,741	11,708	14,554	14,476	21,393	18,751
Other	8,630	13,057	14,518	17,284	19,587	19,222
Total	**111,762**	**129,852**	**127,496**	**128,347**	**150,234**	**148,241**

Future Elements of Expense total Emergency Response program

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	89,601	91,443	90,550	89,068	89,068
M&S	4,135	4,135	4,135	4,135	4,135
A/P	14,259	18,063	18,283	18,283	18,283
Other	14,166	14,166	14,166	14,166	14,166
Total	**122,160**	**127,806**	**127,133**	**125,651**	**125,651**

Meters and Other Customer Equipment

Incremental Change due to this project to the Meters and Other Customer Equipment program
Future Elements of Expense

EOE	Request 2020	Request 2021	Request 2022
Labor	(333)	(860)	(1,087)
M&S	-	-	-
A/P	-	-	-
Other	-	-	-
Total	**(333)**	**(860)**	**(1,087)**

Historical Elements of Expense total Meters and Other Customer Equipment program

EOE	Actuals 2014	Actuals 2015	Actuals 2016	Actuals 2017	Historic Year (O&M Only)	Actuals 2018
Labor	13,583	14,730	13,055	12,107	8,822	9,332
M&S	229	476	856	642	1,197	1,104
A/P	521	1,216	2,114	1,591	2,542	2,924
Other	(2,090)	(287)	(1,615)	(1,792)	(2,721)	(4,581)
Total	**12,243**	**16,135**	**14,410**	**12,548**	**9,840**	**8,779**

Future Elements of Expense total Meters and Other Customer Equipment program

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	11,546	11,213	10,353	9,266	9,266
M&S	1,366	1,366	1,386	1,386	1,386
A/P	3,618	3,639	3,618	3,618	3,618
Other	(5,668)	(5,688)	(5,688)	(5,688)	(5,688)
Total	**10,862**	**10,529**	**9,669**	**8,582**	**8,582**

Exhibit__(EIOP-8)

T&D Safety and Security

Schedule 1: T&D Safety and Security Capital Program and Project Summary

Electric T&D		**Year Total**			
EIOP - Safety and Security		**Current Budget**			
		Total Dollars ($000)			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
Equipment Purchases					
Organization	**White Paper**				
Substations	Cable Termination Platform Project	1,050	1,050	1,050	3,150
Substations	Cap and Pin Insulator Replacement Program	690	1,000	1,000	2,690
Substations	Critical Infrastructure Protection (NERC) Security Upgrades	975	975	975	2,925
Transmission	Cyber Security	1,000	1,000	1,000	3,000
Distribution	Distribution Electric Control Center Cybersecurity	1,000	1,000	1,000	3,000
Transmission	ECC Facility Security Enhancement	390	400	400	1,190
Transmission	Overhead Tower Rapid Rail Program	976	1,000	1,000	2,976
Substations	Substations Security Enhancements Program	10,000	10,000	10,000	30,000
	Total Safety and Security	**16,081**	**16,425**	**16,425**	**48,932**

Schedule 2: T&D Safety and Security O&M Program Change Summary

Infrastructure Investment Panel				
O&M Program Changes				
EIOP - Safety and Security				
($000)				
		RY1 Program Change	**RY2 Program Change**	**RY3 Program Change**
Safety and Security				
Organization	**Program Change**			
Distribution	Advanced Safety Inspection Repair Program*	2,330	3,600	(5,400)
Transmission	Cybersecurity and Physical	370	-	-
TOTAL ELECTRIC				
	Grand Total	**2,700**	**3,600**	**(5,400)**

** The Advanced Safety Inspection Repair program is funded in the O&M Structures/Poles program*

Schedule 3:

T&D Capital White Paper

Safety and Security

X	Capital
	O&M

2019– Central Operations / Substation Operations

Project/Program Title	Cable Termination Platform Project
Project Manager	John Dorn.
Hyperion Project Number	PR.22105611
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
The Cable Termination Platform Project will modify platforms to provide tethering points via fall arrest posts and movable railing systems for working on the platform. This project will be Substation Operations enterprise wide. Civil Engineering will provide a generic restraint and railing system that can be adapted for use within a Substation. Local structural reinforcement of the termination platform may be required for it to withstand the fall arrest forces.

The objectives of the Cable Termination Platform Project are as follows:

- Provide fall restraint while applying electrical protection (grounds) from cable termination platforms
- Provide fall protection while performing other work from cable termination platforms
- Implement standard designs that are the expected norm in a Substation for restraints or protection
- Ensure all projects are reviewed for fall protection at the design phase
- Ensure that clear direction is provided to workers on the limitations of using the restraint systems

The unit cost is approximately $180,000 for each platform.

Justification Summary:
Injuries increase workmen's compensation and retraining costs, and absenteeism. Injuries also decrease productivity, and employee morale. Our business operates more efficiently when the Company implements well designed engineered safety systems that protect our employees. Con Edison has an active Environmental Health and Safety leadership which results in a rated better place to work, and more satisfied and productive employees.

The East 36th St. accident investigation identified weaknesses in the Company's restraint protocols while working on a cable termination stand. Though these weaknesses were not the cause of the injury to the employee Con Edison recognizes the need to do all the Company can to prevent a reoccurrence. Occupational Safety and Health Administration (OSHA) requires a response to a high hazard type of injury.

Supplemental Information:

- Alternatives: An alternative is to maintain the current practice, with continuation of the identified weaknesses in the restraint protocols while working on a cable termination stand. This alternative is not recommended.

- Risk of No Action: The risk of no action would subject employees and contractors to potential injuries due to weaknesses in the current protocols.

- Non-financial Benefits: Enhance the safety of employees and contractors by protecting them from potentially dangerous falls.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: Existing platforms that lack removable railing systems are not designed for fall arrest forces and must be evaluated. Structural reinforcement may be needed for some of the platforms.

- Project Relationships (if applicable): N/A

Proposed 2019 – 2023

- Con Edison has a population of 82 Termination Stands that require corrective action to install permanent Safety Railings. Each termination stand requires a 5 day outage to perform the railing installation, The stations identified in the program are:
  - Bensonhurst Substation: 5 termination stands
  - Brownsville Substation 9 termination stands
  - Plymouth St. Substation 4 termination stands
  - Glendale Substation 4 termination stands
  - Water St. Substation 4 termination stands
  - Willowbrook Substation 2 termination stands
  - Bruckner Substation 4 termination stands
  - East 29th St. Substation 5 termination stands
  - East 36th St. Substation 5 termination stands
  - East 75th St Substation 5 termination stands
  - Seaport Substation 5 termination stands
  - West 110th St. Substation 10 termination stands
  - West 42nd St. Substation 10 termination stands
  - West 65th St. Substation 10 termination stands
  -

Basis for Estimate: Estimates are based on structural and railing fabrication experience and the costs associated with system outages. The estimate for the fall arrest system and steel reinforcement is $100k and $80k for the removable railing. The plan is to complete four to six per year for 2017-2019, and seven per year thereafter.

Annual Funding Level ($000):

EOE Historical Elements of Expense	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	256	305		101
M&S	-	-		1		3
A/P	-	-	2	18		15
Other	-	-	1	15		54
Overheads	-	-	199	216		65
Total	**-**	**-**	**456**	**556**		**238**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	336	441	441	441	441
M&S	32	42	42	42	42
A/P	80	79	84	88	84
Other	66	84	84	84	85
Overheads	286	404	399	395	398
Total	**800**	**1,050**	**1,050**	**1,050**	**1,050**

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X	Capital
	O&M

2019 – Central Operations / Substation Operations.

Project/Program Title	Cap & Pin Insulator Replacement Program
Project Manager	N/A
Hyperion Project Number	PR.22672373.
Status of Project	Engineering/Planning,
Estimated Start Date	2019
Estimated Completion Date	2023
Work Plan Category	Strategic

Work Description:

Replacement of the Cap and pin insulators with a different type of insulator, Station post insulator, is planned to be completed within 4 years, starting 2019. Engineering will specify the acceptable replacement equipment to be used at each station. In some select locations an alternate fix is to remove the cap and pin insulators and replace the existing bus with flexible cable, improving the design. The cost will be similar because new cables and connectors will be required instead of station post insulators.

The Con Edison system have thousands of cap and pin insulators which are used to support bus at various voltages, mainly 138 kV. They are used in almost every transmission station on our system. They perform acceptably except when they are mounted at some position other than 90 degrees (straight up and down). When they are mounted at a 45 degree angle they develop cracks and fail. The insulators have a known issue called cement growth that puts pressure on the insulator's porcelain and cracks it. One caused the equipment to be removed from service category 1 and another caused a flashover to ground on our 138 kV system. Others have had pieces fall to the ground without causing a flashover. This is a safety hazard for station personnel because they can work under these insulators which have broken and fallen.

Justification Summary:

The application of the cap and pin insulators used in this configuration (mounted at 45 degrees) is a poor design and needs to be changed. There have been multiple failures resulting in flashovers to ground or requiring the removal of equipment on a category 1 emergency due to this failure mode. A system wide program is required to remove the insulators and replace them with an acceptable design. There are two design options. Engineering will evaluate the best solution to be implemented for each location. The cost for each solution is approximately equivalent.

We have had this failure mode occur several times at various stations (E179th st, Jamaica, E13th st, Elmsford). When they are mounted at an angle, the increased pressure causes the insulator to fail. These insulators that are used in this manner require replacement to prevent future failures on our transmission system. It is a reliability concern as well as a safety hazard for our station personnel.

Supplemental Information:

- Alternatives: An alternate strategy would be to replace the Cap and Pin Insulators with new cable. This option is the second of two, which Engineering will determine the best option for each location.

- Risk of No Action: This is unacceptable for system reliability and safety. Several of these insulators have fallen or have had pieces fall, causing a hazard to station personnel because they can work under these insulators which have broken and fallen. Also several faults to ground have occurred when these insulators have failed and fallen to the ground.

- Non-financial Benefits: The non-financial benefits include an increase in system reliability as well as an increase in station safety. In several past incidents the cap and pin insulators have failed and caused a fault on our transmission system. Additionally it is a safety concern to have equipment fall to the ground with personnel walking under it.

- Summary of Financial Benefits (if applicable) and Costs: Benefits include the avoided cost of a possible environmental impact, damage to neighboring equipment or property due to failure. Also a typical replacement would be less costly than a failed unit.

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable): **N/A**

- Basis for Estimate: Engineering estimates

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	88	121	175	175	175
M&S	125	172	250	250	250
A/P	120	162	240	240	240
Other	34	28	39	44	39
Overheads	133	207	296	291	296
Total	**500**	**690**	**1,000**	**1,000**	**1,000**

X	Capital
	O&M

2019 – Central Operations/Substation Operations

Project/Program Title	Critical Infrastructure Protection (NERC) Security Upgrades
Project Manager	Arman Shiplu.
Hyperion Project Number	PR.3ES0500
Status of Project	In Progress
Estimated Start Date	2013
Estimated Completion Date	2023
Work Plan Category	Regulatory Mandated

Work Description:
This is a continuation of a program which funds security enhancements that will be implemented at 101 Substation Operations facilities as a result of the new North American Electric Reliability Corporation NERC Critical Infrastructure Protection (CIP) version 6 requirements. Substation cyber systems that are critical to the reliable operation of the electric system will require physical and electronic perimeters, the establishment of cyber security controls and a Work Management System.

The 16 Medium substations were completed in 2016. The 23 Low transmission substations will be completed by 2019.

In addition, area substation baseline cyber asset and cyber security controls will be placed as follows: 2020 – 15 area substations, 2021 – 15 area substations, 2022 – 15 area substations, 2023 – 17 area substations.

Justification Summary:
NERC Standards provide a cyber-security framework for the identification and protection of critical cyber assets. These standards recognize the different roles of each entity in the operation of the electric system, the criticality and vulnerability of the assets needed to manage the risks to which they are exposed.

The FERC approved CIP Version 6 standard has significantly changed the requirements for determining a cyber-asset. One of the fundamental differences between CIP versions 3 and 6 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying bulk electric system BES Cyber Systems. In transitioning from Version 3 to Version 6, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets. BES Cyber Systems and their associated BES Cyber Assets have varying impact on the reliable operation of the BES.

Any computer system or group of computer systems that can, if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact one or more BES Reliability Operating Services is categorized as a BES Cyber System. These systems must be categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact.

CIP Version 5 sets up distinct requirements for different impact categories of facilities. There are three impact categories, defined as High, Medium, and Low. The High category is for the control centers (the electric control center (ECC) and Alt electric control center (AECC); with Medium and Low category defined for substations. In general, there are 111 requirements imposed for the High and Medium Impact

BES Cyber Systems. Presently our review of Medium, and Low guidelines place the sixteen substations in the Medium category, twenty three substations in the Low category, and sixty two substations that are not subject to the Version 5. NERC enforcement on Medium sites is April 2016 and Low sites is April 2017. In addition, these NERC secure controls will be implemented on non-BES area substations from 2017 to 2020.

To meet the various requirements of CIP Version 6 and industry best practices at these stations, the BES Cyber System requires significant physical access protection/controls, electronic access protection/controls, controls on the design information (access control to the drawings designs – Team Center), and a work management system to address baseline configuration and change management.

Supplemental Information:

- Alternatives: There is no alternative to performing the work, as it is mandated by FERC/NERC.

- Risk of No Action: Taking no action leave the Company subject to substantial fines for failure to comply with a FERC/NERC mandated program. It would also leave the Bulk Electric System vulnerable to cyber-attacks.

- Non-financial Benefits: Business and operational demands for managing and maintaining a reliable BES increasingly rely on cyber assets supporting critical reliability operating services and processes to communicate with each other, across functions and organizations, for services and data. This program ensures compliance with regulatory mandates (FERC/NERC & NPCC Northeast Power Coordinating Council) and addresses Cyber Security Corporate risk.

- Summary of Financial Benefits (if applicable) and Costs: Avoidance of fines up to $1 million per day.

- Technical Evaluation/Analysis: N/A as this is regulatory mandated.

- Project Relationships (if applicable): N/A

- Basis for Estimate:
    - Over the course of 5 years, labor includes 14,000 man hours of work performed to support the impact categorization of baseline configurations, physical and electronic perimeter controls at BES and Non-BES substations
    - A new test environment will be created to manage patch management for various operational cyber assets. Human Machine Interface (HMI) computers, programmable logic controllers, relay, network switches and various other new devices will be purchased. In addition, software such as anti-virus, intrusion detection software, password management software will be purchased to harden the cyber assets. New compliance tools and cyber security web page will also be created in order to manage the evidence required NERC Reliability Standard Worksheet (RSAW). The cost of this will be 800K.
    - Change Management data server and servers to manage passwords at substations will be used. This cost will be 200K.
    - Purchase Transient Cyber Asset laptops dedicated to each impacted substation

	2019 (NERC low sites)	days to complete	12 hour days
1	Dunwoodie North 138	15	180
2	Dunwoodie South 138	15	180
3	East 179 138	15	180
4	Fox Hills 138	20	240
5	Greenwood 138	15	180
6	Hell Gate 138	20	240
7	Hudson Ave E. 138	15	180
8	Pleasantville 345	20	240
9	Sherman Creek 138	25	300
10	Tremont 345	20	240
11	Academy 345	25	300
			2460

	2020 (Manh.)	days to complete	12 hour days
1	AVENUE A	15	180
2	CHERRY STREET	15	180
3	EAST 29TH STREET	15	180
4	EAST 36TH STREET	20	240
5	EAST 40TH STREET NO.1	15	180
6	EAST 40TH STREET NO.2	20	240
7	EAST 63RD STREET NO.1	15	180
8	CORONA NO.1 - 27KV	25	300
9	CORONA NO.2 - 27KV	25	300
10	GLENDALE	15	180
11	JAMAICA - 27KV	20	240
12	FOX HILLS - 33KV	25	300
13	FRESH KILLS - 33KV	25	300
14	WAINWRIGHT	20	240
15	WILLOWBROOK	20	240
			3480

	2021 (manh. & Queens)	days to complete	12 hour days
1	WOODROW	20	240
2	TRADE CENTER NO.1	15	180
3	WEST 110TH STREET NO.1	15	180
4	WEST 110TH STREET NO.2	15	180
5	WEST 19TH STREET	15	180
6	WEST 42ND STREET NO.1	20	240
7	WEST 42ND STREET NO.2	20	240
8	NORTH QUEENS	15	180
9	BENSONHURST NO.1	15	180
10	BENSONHURST NO.2	15	180
11	BROWNSVILLE NO.1	15	180
12	BROWNSVILLE NO.2	15	180
13	BRUCKNER	20	240
14	EAST 179TH STREET - 13KV	30	360
15	NEWTOWN AREA SUBSTATION	30	360
			3300

	2022 (B/Q/SI & BX)	days to complete	12 hour days
1	EAST 63RD STREET NO.2	20	240
2	EAST 75TH STREET	25	300
3	LEONARD STREET NO.1	15	180
4	LEONARD STREET NO.2	15	180
5	MURRAY HILL	25	300
6	PARKVIEW AREA SUBSTATION	25	300
7	GREENWOOD - 27KV	20	240
8	PLYMOUTH	15	180
9	WATER STREET	10	120
10	CEDAR STREET	20	240
11	ELMSFORD NO.2 - 13KV	25	300
12	BUCHANAN - 13KV	20	240
13	HELLGATE - 13KV	20	240
14	MOTT HAVEN 13KV	25	300
15	SHERMAN CREEK - 13KV	25	300
			3660

	2023 (BX/West.)	days to complete	12 hour days
1	WEST 50TH STREET	20	240
2	WEST 65TH STREET NO.1	20	240
3	WEST 65TH STREET NO.2	20	240
4	ASTOR	25	300
5	SEAPORT NO. 1	25	300
6	SEAPORT NO. 2	25	300
7	PARKCHESTER NO.1	20	240
8	PARKCHESTER NO.2	20	240
9	GRANITE HILL	25	300
10	GRASSLANDS	25	300
11	HARRISON	25	300
12	MILLWOOD WEST - 13KV	20	240
13	OSSINING WEST	15	180
14	PLEASANTVILLE - 13KV	20	240
15	ROCKVIEW	30	360
16	WASHINGTON STREET	20	240
17	WHITE PLAINS	20	240
			4500

Manhattan station
Queens
Staten Island
Brooklyn
Bronx
Westchester

Annual Funding Level ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	429	381	172	97		181
M&S	510	367	250	106		266
A/P	496	271	202	52		68
Other	7	150	7	41		4
Overheads	2664	271	247	119		183
Total	**1,706**	**1,440**	**877**	**415**	-	**702**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	147	205	205	205	210
M&S	167	234	234	234	240
A/P	126	183	185	185	190
Other	38	49	51	55	52
Overheads	189	304	300	296	308
Total	**667**	**975**	**975**	**975**	**1,000**

X	Capital
	O&M

2019 Capital - Central Operations/System & Transmission Operations

Project/Program Title	Cyber Security
Project Manager	David Wernsing
Hyperion Project Number	PR.23287750
Status of Project	Ongoing
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Regulatory

Work Description:
To improve Con Edison's cybersecurity posture, increase the ability to detect threats and attacks against the Company's systems, enhance response to cybersecurity incidents, improve the ability to recover from damage to systems, find new and latent vulnerabilities in the company's systems, and maintain our ability to comply with expanding cybersecurity regulatory requirements, System Operation is increasing the investment in and pursuing a long term cybersecurity program. Con Edison will continue to evaluate and implement advancements in Intrusion Detection / Protection Systems in the Information Technology and Operations Technology spaces. Implementation of the Company's recently acquired centralized backup system will dramatically improve disaster recovery and lay the foundation for improving the Mobile Control Center. Consultants and contractors will build features and implement new enhancements, including new reporting and alerting capabilities in Con Edison's Security Information and Event Monitoring systems and implement the technology uplift needed for the new capabilities. Expanding the Company's EMP/IEMI shielded standby systems to include the entire internal infrastructure will improve the system's resiliency. Updates to the automated notification and communication systems will improve the response to detected threats. Upgrading the authentication servers will provide enhanced protection from several credential theft techniques preventing threat actors from gaining a foothold and escalating privilege in Con Edison's systems.

In addition to the work outlined above, new systems and requirements will be identified as new technologies become available and opportunities are identified to further secure the voice and data communication systems, contingency planning, recovery capabilities, automate processes and in general fortify the Company's cybersecurity posture in all framework functions (Identify, Protect, Detect, Respond and Recover). It is also anticipated that the North American Electric Reliability Corporation (NERC) Cyber Security (CIP) and Public Service Commission (PSC) requirements will continue increasing in scope and complexity. As these requirements are identified, solutions will be engineered and implemented.

Justification Summary:
System Operation relies heavily on its cyber assets for operation, analysis, and day-to-day business. Nearly every tool used to operate Con Edison's electric system and support that operation is dependent on the cyber assets. These systems include supervisory, control and safety systems like: GE XA21 Energy Management System (EMS), Operational Management Systems (OMS), including the Feeder

Management System (FMS) and FMS Online. Additional systems include analysis and decision support systems like Plant Information (PI) and Rapid Restore, infrastructure support systems like Active Directory, antivirus and patch management, as well as communication systems like District Operations (DO) Direct, email, and Voice data logger. As the sophistication of cyber threats increases, so too must the systems that protect our critical cyber assets from these threats.

Segregating systems by functionality into separate security zones follows industry best practices and permits customization of each system's protection scheme. This will protect each system from the vulnerabilities of other systems, thereby limiting the exposure to cyber threats. Additionally, segregating assets by function will reduce the number of assets subject to the NERC CIP regulations, reducing the Company's compliance risk.

The requirements of versions 5 and 6 of the NERC CIP standards have drastically changed the patch management, asset monitoring, and configuration control requirements. These areas are the most labor intensive portions of our compliance program. Several additional system enhancements will further address certain asset monitoring requirements. One focus of this project is continue on the path of automating the portions of our patch management and configuration control processes that can be automated.

The Intrusion Detection System (IDS) that has been installed in both control centers will continue to be upgraded, fine-tuned and incorporated into the Company's cyber security strategy. IDS is another important tool used to maintain a strong cybersecurity posture. As the above mentioned changes are implemented, the IDS will also require additional expansion to ensure all network traffic is monitored and modeled in the system.

Supplemental Information:

- Alternatives: None. The project follows industry and corporate standards to meet regulatory obligations.
- Risk of No Action: This will expose the Company to possible Cybersecurity regulatory violations (and fines) related to the applicable requirements of the NERC CIP Standards. Failing to maintain an updated security posture also increases the likelihood that our control systems will be compromised.
- Non-financial Benefits: Improved ability to detect and protect System Operation's critical cyber assets from cyber threats.
- Summary of Financial Benefits (if applicable) and Costs: Fines for NERC CIP violations can be as high as $1 million per day per infraction. Compliance with several other NERC reliability regulations would be jeopardized if cybersecurity is not maintained.
- Technical Evaluation/Analysis: Not Applicable
- Project Relationships (if applicable): This project will provide cybersecurity for all System Operation cyber assets and is thereby related to all System Operation projects using cyber assets. Examples include; Operations Network for the Energy Management System (EMS); EMS Reliability, Energy Control Center (ECC) and Alternate Energy Control Center (AECC); Operation Management System Enhancements.
- Basis for Estimate: Historical spending, approved changes to NERC CIP standards, and vendor estimates.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	7	12	134	97		45
M&S	-	-	-	-		-
A/P	40	851	380	896		393
Other	-	-	-	-		-
Overheads	5	32	92	71		36
Total	**52**	**895**	**606**	**1,064**		**474**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	100	100	100	100	100
M&S	-	-	-	-	-
A/P	773	774	774	774	774
Other	69	69	69	69	69
Overheads	58	57	57	57	57
Total	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Distribution Electric Control Center Cybersecurity
Project Manager	David Pearce
Hyperion Project Number	PR.22691545
Status of Project	In Progress
Estimated Start Date	9/15/2017
Estimated Completion Date	12/31/2022
Work Plan Category	Strategic

Work Description:

Con Edison's Distribution Electric Control Centers (DECC) require continued investments to reduce risks from cyber-attacks through a strategy of defense in depth and layers of security through deployment of new technologies, benchmarking best practices, and dedicated cyber-security experts. This ongoing investment is required so the DECC can incorporate security products used in these layers, and develop the capability to detect and mitigate latest cyber-attack methods to ensure continuity of operation.

The plan calls for $5.75 million capital investments over the next three years under this project to increase the operational resiliency and reliability of DECC. The technologies are focused on enhancing the logging, monitoring, auditing, and recovery capability of the operational networks to help prevent and/or isolate a cyber-attack, and provide forensics should some type of attack succeed. This is a focused effort for DECC cyber-security, and cyber-awareness, in coordination with corporate cyber security initiatives. The planned investments are intended to prevent unauthorized access, and improve resiliency and recoverability of the DECC's computing resources, especially with respect to its systems. The architecture changes include segmentation of the network and applying security layers between servers and DECC Local Area Networks (LANS), as well as segregation of roles. The investment plan under this project includes deployment of new technologies to enhance the protection of DECC via enhanced logging, monitoring, and auditing.

The following elements, based on funding requirements and priority, are proposed 2017-2019:

New Disaster Recovery Systems to reduce recovery times and increase speed of restoration.

- Purchase and implement a new unified backup solution for the DECC
- Purchase and deploy new DECC network elements to enhance IslandNet.
- Purchase and deploy a new DECC license management solution, in conjunction with corporate initiatives.

New Security Systems to prevent cyber attacks

- Purchase and implement a new enterprise password manager for the DECC.
- Purchase and deploy new SCADA antivirus endpoint protection for Linux systems.
- Purchase and deploy new firewalls to physically separate SCADA from non-SCADA LANs.
- Purchase and implement servers and infrastructure for a new SCADA domain in the DECC.
- Purchase and deploy DECC specific multi-factor authentication for SCADA systems and Islanding.

- Purchase and deploy database and web firewall technology on external facing servers connecting to databases inside the DECC perimeter.

New Monitoring Systems to detect and mitigate

- Implement a Security Information Event Monitoring (SIEM) system (SPLUNK) for advanced event correlation, logging, and data analysis in the DECC (Ongoing and in progress)
- Purchase and implement additional features of Intrusion Prevention (e.g. Tipping Point) technologies in the DECC.

- Purchase and implement new auditing tools for SCADA and related systems in conjunction with corporate cybersecurity initiatives.
- Purchase and deploy Cisco ISE NAC solution, specific to the DECC, for network protection
  - Purchase and deploy an endpoint intrusion detection application and servers for automating the collection of threat and vulnerability alerts and integrate into the SIEM (Splunk).

The following elements, based on funding requirements and priority, are proposed 2020-2022:

New Monitoring Systems to detect and mitigate

- Purchase and deploy new vulnerability scanning technology for SCADA systems.
- Purchase and deploy next generation application firewall technology for the DECC, in coordination with the corporate CST.
- Purchase and deploy next generation Intrusion Prevention System platform for the DECC, in coordination with the corporate CST.
- Purchase and deploy next generation data masking/encryption technologies for data at rest and in motion for the DECC, in coordination with the corporate CST.
- Purchase and deploy servers and network services to implement self-contained data center operations for DECC (e.g. Solarwinds, ARMS, etc.).

New Security Systems to prevent cyber attacks

- Purchase and deploy new physical scanning technologies to prevent physical intrusions.
- Purchase and implement consolidated physical/logical intrusion hypervisor.
- Purchase and deploy DECC runtime application self-protection technologies.

Justification Summary:

Cybersecurity requirements for Information Technology systems associated with the SCADA systems have continued to grow as the risks and threats of cyber-attack have increased. Federal legislation and regulatory standards and present risks for fines associated with failing to comply with standards. The risk to availability and reliability of the Company's electric distribution SCADA systems increases greatly without the latest technology and formal cyber and administrative polices to protect these assets.

Supplemental Information:

- Alternatives: The alternative option is to operate DECC SCADA systems as they are today, supported by current technology. This approach will not adequately protect SCADA data and control, or defend against new threat vectors and techniques. This option is not recommended as it opens Con Edison to security threats.

- Risk of No Action: New security technology is required to protect SCADA systems, prevent unauthorized access, and safely deliver energy. Vendors are trusted to provide effective security.

Failure to address this will place these systems at risk and they will be vulnerable to targeted attacks, and where regulatory standards are mandated, put us at risk for fines due to non-compliance.

- Non-financial Benefits: This project will allow for improved availability and reliability of current and new DECC SCADA, or otherwise critical, systems. Today's technology allows for greater automation, remote control, and data acquisition to help improve efficiencies, and allow potential cost reductions associated with these benefits. An enhanced cyber-security support structure will allow more systems to be used, to segregate, secure, and improve energy delivery.

- Summary of Financial Benefits and Costs: The cost estimates of a cyber-breach to DECC SCADA systems can vary greatly based on the impact. In a worst-case scenario, the threats to energy delivery and, personnel and public safety are significant, and must be considered.

- Technical Evaluation/Analysis: Information Technology performs planning and analysis on all technologies introduced and policies established. Cybersecurity policies and procedures are implemented in conjunction with the IT strategy and vision planning process. Interaction with IT advisors, vendors, and Company employees ensure the selection of the optimal solutions. Each implementation is done with appropriate technology evaluations and commercial Request for Proposals (RFPs), as applicable, before selection and rollout.

- Project Relationships (if applicable): Grid Modernization projects including Dynamic Feeder Rating, Disturbance Monitoring system and high tension monitoring are related to this project. Also, new utility of the future initiatives like Advanced Metering Infrastructure (AMI), Reforming the Energy Vision (REV), and the introduction of distributed generation will increase the cybersecurity risk and require investment in these areas.

- Basis for Estimate: Historic purchases are used as well as vendor presentations and Internet sources.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	77	124	77			357
M&S	2600	2577	2600	86		585
A/P	1333	1807	1240	625		1,223
Other	201	2	180			188
Overheads	159	439	155	10		228
Total	**4370**	**4949**	**4252**	**721**		**2,580**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	-	-	-	-	-
A/P	907	907	907	907	907
Other	81	81	81	81	81
Overheads	12	12	12	12	12
Total	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**

X	Capital
	O&M

2019 – Central Operations/System & Transmission Operations

Project/Program Title	ECC Facility Security Enhancement
Project Manager	Scott Gross
Hyperion Project Number	PR.22950477
Status of Project	Ongoing
Estimated Start Date	Ongoing
Estimated Completion Date	December 2023
Work Plan Category	Regulatory Mandated

Work Description:
This project will add, as required, new equipment to the existing physical security systems at the Energy Control Center (ECC) and Alternate Energy Control Center (AECC). Because this is a North American Electric Reliability Corporation (NERC) and a Critical Infrastructure Protection (CIP) Compliant Building, the location and type of security equipment in use must be held as confidential (BESCSI – Bulk Electric System Cyber System Information).

Justification Summary:
The control centers provide an essential service, each having full remote control capability of the electric and steam systems. Physical security systems must be maintained at levels that provide proper access control and allow for both local and remote monitoring. In addition, NERC policies require specific levels of physical security for critical cyber locations, which this project will address as necessary. Additional security enhancements will be needed to keep up with emergent NERC CIP requirements.

Supplemental Information:

- Alternatives: N/A
- Risk of No Action: May create a non-compliance issue for Con Edison and result in a monetary penalty imposed by Northeast Power Coordinating Council (NPCC)/ NERC. In addition, without upgrades, existing measures may not be adequate to meet future security threats.
- Non-financial Benefits: Strengthens the defenses for critical facilities; helps Con Edison in implementing Department of Homeland Security recommendations; enables NERC reliability standards to be met and avoids potential penalties associated with non-compliance.
- Summary of Financial Benefits (if applicable) and Costs: N/A
- Technical Evaluation/Analysis: N/A
- Project Relationships (if applicable): Cyber Security Program.
- Basis for Estimate: System Operations worked with the Corporate Security Technical Team to evaluate the ECC and the AECC's Security needs and that was the basis for the funds for years 2019-2023.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1	5	16	6		20
M&S	0	0	0	0		0
A/P	36	544	147	69		112
Other	-	-	-	-		-
Overheads	15	151	45	22		20
Total	**52**	**700**	**208**	**97**		**152**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	50	50	50	50	50
M&S	-	-	-	-	-
A/P	160	287	297	297	297
Other	14	26	26	26	26
Overheads	26	27	27	27	27
Total	**250**	**390**	**400**	**400**	**400**

X	Capital
	O&M

2019 Central Operations/System & Transmission Operations

Project/Program Title	Overhead Tower Rapid Rail Program
Project Manager	Mark Davis
Hyperion Project Number	PR.22679504
Status of Project	Ongoing
Estimated Start Date	January 2016
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
This is a program to install step bolts and a permanent wire rope (Rapid Rail) system on frequently accessed overhead transmission towers (to be used by personnel climbing the structures). The Rapid Rail system serves as a safe and efficient means to comply with new OSHA regulation 1910.269(g)(2)(iv)(C)(3) (which requires that fall protection be used by qualified employees while climbing or changing locations on poles, towers or similar structures). The Rapid Rail system allows personnel to climb overhead towers while establishing and maintaining 100% fall protection by tying off to the permanently installed wire rope. This program will target roughly 50 structures a year (for installation).

Justification Summary:
OSHA regulation 1910.269(g)(2)(iv)(C)(3) went into effect in April, 2015 and requires that qualified personnel use fall protection while climbing or changing locations on poles, towers or similar structures. Company procedures were adjusted to ensure compliance with this new standard but the resulting procedures did not provide the most efficient or safest possible means of tower climbing for company personnel. The current procedure for climbing overhead transmission towers requires the use of double lanyards and large pelican hooks to ascend the tower. This equipment is cumbersome and has negative ergonomic effects on the employees. Another alternative is the use of a shepherd's hook, rope line and the "first person up, last person down" method. The "first person up, last person down" method means that the initial climber uses a shepherd's hook to ascend the tower. Once in position, the employee would secure a safety line to facilitate subsequent crewmembers climbing the tower while tying off to the line as a means of fall protection. Although these procedures comply with the new OSHA standard, they are time intensive and physically taxing, and the "first person up, last person down" method requires that the initial climber carry roughly 30 lbs. of equipment up the tower.

The Rapid Rail system will include installing step bolts and a permanently installed wire rope. The step bolts will allow personnel to climb the tower in a safe and efficient manner while establishing fall protection by tying off to the wire rope. The permanent installation of the wire rope will eliminate the need for the double lanyards and pelican hooks and the first person up, last person down" method of establishing a rope from which to tie off. The permanence of the system will also significantly reduce the amount of equipment that must be carried by personnel when climbing towers, making the process safer and more efficient. A high level time study estimates that, once the system is installed on a tower, the labor hours required to have a 4 person crew climb a tower can be reduced by as much as one third. This productivity gain will have a positive effect on jobs that require tower climbs as well as potentially improving responses to various emergencies. This program will target towers that are in need of regular access.

This method would also be needed to apply grounds to the next tower closest to the nearest substation (prior to climbing the tower where the work will be performed), thereby doubling the use of this physically taxing method.

Supplemental Information:

- Alternatives: The only alternative to executing this program would be to use the existing procedures to climb overhead towers and establish fall protection for personnel with the double lanyards and large pelican hooks to ascend the tower. This equipment is cumbersome and has negative ergonomic effects on the employees. A second alternative is to utilize the first person up, last person down" concept. This alternative does not require capital investment but requires personnel to carry 30+ lbs. of extra equipment in an already arduous activity and is an inefficient work practice.
- Risk of No Action: Although the OSHA regulation recently changed to require fall protection, it allows for the use of the "first person up, last person down" method of shepherd's hook and a positioning belt as fall protection for the initial climber. As safety procedures continue to evolve, there is a possibility that the regulations change again in such a manner that would require permanent installation, such as the Rapid Rail system, in order to comply.

- Non-financial Benefits: The installation of the Rapid Rail system will eliminate the need for extra equipment to be carried by personnel while climbing towers where it is installed; this will lead to increased efficiency and safer work conditions.

- Summary of Financial Benefits (if applicable) and Costs: Going forward, the time required to have a four person crew climb a tower can be reduced as much as one third.

- Technical Evaluation/Analysis: Not applicable

- Project Relationships (if applicable): The towers targeted for installation of the Rapid Rail system will be coupled with towers that have already been selected for reinforcement under other work packages (in order to gain efficiency in execution).

- Basis for Estimate: The basis for the estimate is an engineering estimate, based on a conceptual scope of work, of approximately $20,000 per tower and a target of 50 towers per year.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	3	698		200
M&S	-	-	-	-		100
A/P	-	-	156	18		50
Other	-	-	-	-		4
Overheads	-	-	37	482		400
Total	-	-	**196**	**1,198**		**754**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	185	403	407	402	405
M&S	8	47	50	50	50
A/P	240	490	500	500	500
Other	25	-	-	-	-
Overheads	23	37	43	48	45
Total	**481**	**976**	**1,000**	**1,000**	**1,000**

X	Capital
	O&M

2019 – Central Operations/Substation Operations

Project/Program Title	Substations Security Enhancements Program
Project Manager	Mike Lentini
Hyperion Project Number	PR.2ES7100
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Regulatory Mandated

Work Description:

This program is required to systematically upgrade substation security systems throughout New York City's five boroughs and Westchester, Rockland and Dutchess Counties. Security upgrades include the installation of fencing, surveillance system, access control systems and perimeter intrusion detection systems.

The Company is currently working on security upgrades at the Jamaica, Greenwood, Astoria West, Queensbridge, Seaport and Plymouth Street Substations. For 2017 to 2021, the Company's goal is to continue to install security upgrades for Transmission/Switching/Area Substations and public utility station PURS facilities in priority order. The schedules and prioritization are subject to change based on available funding and coordination with other capital work.

Justification Summary:

The security upgrades are necessary to address the threat of sabotage or terrorism, vandalism, theft and unauthorized access to the substations per the requirements of Con Edison Security Specification CE-ES-2002-24. The sabotage/terrorism incidents at the Metcalf bulk power substation in California in April 2013 in which several transformers were damaged by gun fire in a well-coordinated attack and of an Entergy high-voltage transmission tower in Arkansas in August 2013 that was brought down after someone deliberately removed the bolts from its base, underscore the importance of installing state of the art security systems at the Company's substations. In view of these events and others, the Federal Energy Regulatory Commission (FERC) directed the North American Electric Reliability Corporation (NERC) to develop reliability standards requiring owners and operators of the bulk power system to address risks due to physical security threats and vulnerabilities. This program aligns with the aforementioned directive. In addition, this work is in accordance with the recommendations made by the Public Service Commission with regards to having security measures in place to enhance protection and increase deterrence of attacks against Con Edison's facilities.

Supplemental Information:

- Alternatives: The only alternative is to take no action.

- Risk of No Action: Taking no action is not a recommended approach as these security enhancements are necessary to address regulatory requirements concerning physical security threats to electric power facilities. These upgrades provide substation facilities with protection against the threat of vandalism, theft, and security breaches. These acts have the potential to compromise electric service to our customers and increase the risk to the safety of the public and Company personnel. Undertaking this program will also comply with Con Edison Security Specification CE-ES-2002-24 as well as the associated regulatory requirements.

- Non-financial Benefits: This program supports the coordinated effort between government agencies and utilities to protect against physical security threats to the nation's power facilities. This program provides risk mitigation and supports the Company's mission to provide safe, reliable energy to our customers.

- Summary of Financial Benefits (if applicable) and Costs: A significant security incident would result in a substantial impact to the Company to respond to the emergency and implement recovery efforts.

- Technical Evaluation/Analysis: The measures to be deployed have been reviewed with/by the Company's security experts.

- Project Relationships (if applicable): At stations where storm hardening initiatives are imminent, this program can potentially be impacted requiring additional engineering and planning.

- Basis for Estimate: Near term work based on Engineering estimates based on similar work done in the past. Outer term work is based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature.

Annual Funding Level ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	7,767	2,041	2,790	1,681		4,210
M&S	6,331	876	1,830	1,693		2,320
A/P	2,356	3,311	2,796	2,948		3,667
Other	404	173	141	-29		299
Overheads	11,560	3,785	3,637	2,777		4,112
Total	**28,419**	**10,186**	**11,194**	**9,070**	-	**14,608**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	2,076	1,384	1,384	1,350	2,025
M&S	2,307	1,538	1,538	1,500	2,250
A/P	6,150	3,765	3,808	3,945	5,850
Other	666	440	440	430	645
Overheads	3,801	2,873	2,830	2,775	4,230
Total	**15,000**	**10,000**	**10,000**	**10,000**	**15,000**

Schedule 4

T&D O&M White Papers

Safety and Security

	Capital
X	O&M

2020 – Electric Operations

Project/Program Title	Advanced Safety Inspection and Repair
Project Manager	Stan Lewis/Maria Rodriguez
Status of Project	Ongoing
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:

Con Edison proposed in its 2016 Electric Rate Filing 16-E-0060 a Safety Inspection Program (SIP) pilot that included current and infrared enhanced inspections of the Underground Network and Underground Residential Distribution (UG/URD) assets and the targeted mobile contact voltage scanning of areas with elevated energized object generation rates. Both the Enhanced Inspection and Targeted Mobile Scanning pilots have been successful in reducing manhole and electric shock events.

UG/URD Asset Optimized SIP Inspection Pilot – This program funds the inspection of UG and URD distribution structures to identify conditions that can cause or lead to safety hazards or adverse effects on the system's performance. The Company has over 280,000 distribution manholes, service boxes, transformer vaults, and URD assets. Starting in 2020, the SIP program will change to pilot inspections on assets that pose the highest risk to public safety and system reliability. Assets will now be classified into two groups, Periodic Inspection (PI) group - consisting of bi-yearly and eight year inspection cycle tiers; and, a non-Periodic Inspections (NPI) group for the remainder of assets that will be inspected only with routine work. Of the 280,000 UG and URD assets, 150,000 or 54% of these assets will be part of the PI group and the remainder part of the NPI group assets.

These inspections will continue to be performed by contractor and Con Edison crews, but under the pilot be supplemented and supplanted with new technologies. Technology like the Structure Observation System (SOS) platform that was first introduced in late 2016 and has since evolved and expanded to include even greater sensor capability. Assets equipped with SOS monitoring technology will have near continuous inspection. Another emergent technology, is through cover inspection, which allows the operator to inspect the equipment in the structure without entering.

In order to complete an UG/URD inspection, the equipment within that asset needs to be visible. The standard of visibility for an inspection will be line of sight to the equipment from five feet. Line of sight will not be considered obstructed where limited debris and or water is present on the equipment. While the flush rate from the first four years of Cycle 3 Inspections reached 46%, the flush standard described above may be closer to 23%. Due to the flush rate exceeding projections, the inspections contractor notified the Company they could not complete their work at the contracted rate. The agreement was subsequently amended to separate the cost of flush from inspection resulting in a lower inspection unit cost and stand-alone flush unit cost.

1) **UG/URD Asset Optimized Repair** – Defects will be selected and identified based on safety hazard, and or adverse effect to reliability. These defects will either be repaired at the time of discovery or scheduled for repair according to the time frames specified by the revision to the New York State Public Service Commission order Instituting Safety Standards adopted December 10, 2008 Case 04-M-0159. The UG/URD Asset Optimized SIP Repair pilot will now include defects found through SOS monitor and through cover inspection. A repair and prevention mechanism will also include the placement of structure fill bags into structures that will reduce the chance of a non-accessible defect resulting in an event.

2) **OH 5-Year Inspection** – This program funds the inspection of overhead distribution poles to identify conditions that can cause or lead to safety hazards or adverse effects on the system's performance. The Company will perform inspections of approximately 20% of these system assets in each year of the program. Each asset will be inspected at least once as part of the five year inspection cycle. The workforce performing inspections consists of contractor and Con Edison inspection, maintenance, and construction crews.

3) **OH 5-year Repair** – This program funds the repair of defects identified during the OH 5-year inspections. Such defects may lead to safety hazards or have adverse effects on the system's performance. Defects found as a result of the inspections that are not repaired at the time of initial inspection will be scheduled and repaired according to the timeframes specified by the revision to the New York State Public Service Commission order Instituting Safety Standards adopted December 10, 2008 Case 04-M-0159.

4) **Manual Contact Voltage Testing** – The Manual Contact Voltage Testing Program consists of the annual contact voltage testing of approximately 561,000 utility owned electric facilities and municipality owned street and traffic lights with a focus on improving public safety. The Program identifies possible insulation degradation and or bad connections that might be causing contact voltage on facilities so that crews can make repairs thereby enhancing overall system reliability. A full round of contact voltage testing must be completed by December 31st of each year.

5) **Mobile Contact Voltage Area Optimized Pilot (Vehicle Scans)** – This program covers the surveying of the underground electrical distribution system in the Con Edison service territory for contact voltage utilizing mobile electric field detection. Contact voltages found are safe-guarded until repair crews mitigate the contact voltage conditions. Upon detecting the presence of an electric field by the mobile detector, the testing contractor conducts a manual field investigation to locate the source of the electric field, and mitigate if possible. If immediate repairs to mitigate the condition cannot be made by the contractor, the Con Edison Call Center is notified, the area cordoned off and safeguarded until repair crews respond to the location. Under the New York Public Service Commission (PSC) order Case 04-M-0159, Con Edison is mandated to complete twelve mobile contact voltage scans of the underground distribution system each rate year. In addition, Con Edison is mandated to conduct an annual mobile contact voltage detection survey of the underground electric distribution system in appropriate areas of cities with a population of at least 50,000. The 12 aggregate scans of NYC and 1 scan of Westchester cities with a population of 50,000 or more, are considered the annual cycle scan. The 12 aggregate NYC scans will be area optimized to locations with higher numbers of energized equipment detections with no area receiving fewer than 6 scans in a year. The scan area optimization is projected to reduce the number of electric shocks as the time between detection and safeguarding for the substantial majority of energized objects is reduced. The Mobile Contact Voltage Detection Program has and will continue to make a significant contribution to improving public safety.

6) **<u>Contact Voltage Testing Related Repairs – Streetlights</u>** – This program works with the Manual and Mobile Contact Voltage Testing Programs. Contact voltage conditions discovered on municipality-owned streetlights or other street furniture are repaired under this program. Following a discovery, a crew works to identify the source of the contact voltage and will either make temporary or permanent repairs to mitigate the condition. Making repairs eliminates the contact voltage condition, which improves public safety, and corrects a defect on the system, which improves system reliability.

7) **<u>Contact Voltage Testing Related Repairs – UG</u>** – This program works with the Manual and Mobile Testing Programs. Contact voltage conditions discovered on publically accessible objects (other than public streetlight or street furniture) are repaired under this program. Following a discovery, a crew works to identify the source of the contact voltage and will either make temporary or permanent repairs to mitigate the condition. Making repairs eliminates the contact voltage condition, which improves public safety, and corrects a defect on the system, which improves system reliability.

<u>Justification Summary</u>:
The Company is required to perform structure inspections and repairs pursuant to the PSC Safety Order(s) previously mentioned. The SIP UG/URD Asset Optimized Inspection and Repair pilots are expected to reduce events by supporting other higher value initiatives. These initiatives include IR imaging and SOS monitoring, maintenance and repair. The Mobile Contact Voltage Area Optimized Pilot is also expected to reduce the number of electric shocks.

<u>Supplemental Information</u>:

- <u>Alternatives</u>:
  Continue to manually inspect all assets with equal weighting on affixed cycle. Continue to perform mobile scanning with equal weighting on all areas.

- <u>Risk of No Action</u>:
  UG/URD SIP Inspections and Repairs, defect repairs found continue to grow and the defect backlog continues to increase. Enhanced inspections and targeted scans would have to be curtailed and the benefits from these additional scans would not be realized.

- <u>Non-financial Benefits</u>:
  The optimized scanning and inspections performed under this program improve both public safety and system reliability. Changes to the Inspection program will also have wide ranging public benefits from decreased traffic interruptions to noise associated with flushes.

- <u>Summary of Financial Benefits (if applicable) and Costs</u>: See section on basis for estimate.

- <u>Technical Evaluation/Analysis</u>: See justification section.

- <u>Project Relationships (if applicable)</u>: None

- <u>Basis for Estimate</u>:

  OH Inspections: 280,000 poles inspected in 5 years for $2.45M. To inspect 20% or 56,000 poles each year at $8.75/pole.

OH Inspections: Defect repairs made on 3%-5% of Con Edison's 280,000 pole population. Repair of OH defects required 1-2 crews between 2 and 4 hours per location. 1860 poles (3.3%) repaired per year at $1,000 per pole.

UG/URD SIP Inspections: The Company plans to inspect approximately 150,000 (54%) of the 280,000 structures through a combination of targeted, routine (ad-hoc), and technology based inspections. The number of targeted inspections at $475/inspection is projected to be 90,000 (60%).

UG/URD SIP Repairs: Repairs will fund three defect populations, Open Backlogs, New Generation, and Enhanced Inspections.

- Open Backlog: approximately 12,400 structures
- New Generation: approximately 12,000 structures (3 yr.)
- Enhanced Inspections: approximately 1,500 structures (3 yr.)

Funding Request for Incremental Flush
Based on the estimated units remaining in the program, there are 22,905 units that will need to be flushed. The standalone flush costs are projected to cost an additional $21.5M. When taking into account the savings associated with the reduced unit cost for an inspection, the net increase is $8.8M.

Total Planned Units 2020-2022	99,585
Units Needing Flush (23%)	22,905
Total Incremental Flush Cost (Avg Cost $940 per unit)	$21.5M

Manual Contact Voltage (CV) Inspection: The program funds the Annual Manual CV testing of utility owned electric facilities, municipality owned street and traffic lights, and the work management and testing database. Annually, approximately 255,000 facilities not tested by the mobile scan, are manually tested at approximately $7/test.

Mobile CV Inspection: The Mobile program covers the System scans.

- The System is comprised of 13 total scans, 12 aggregate scans in NYC and 1 scan in Westchester for the cities with a population greater than 50K. The annual cost for the System scans is $8.69M per year.

CV Repair: The CV Repair program funds the repairs associated with Energized objects discovered during the manual and mobile inspection process.

- Streetlight: When CV conditions are discovered on municipality-owned streetlights or other street furniture, electric crews will make temporary or permanent repairs to the electrical service. On locations where the CV condition cannot be mitigated by Company forces, the location is safeguarded until the municipality can respond to make the appropriate repairs. The streetlight CV repair program is estimated at $0.698M per year.

- UG CV Repairs: When CV conditions are discovered during the manual or mobile CV Cycle or Targeted Inspection programs, company crews with make temporary or permanent repairs to the electrical service. On locations where the CV condition cannot be mitigated immediately, the location is safeguarded until a repair crew can respond to make the appropriate repairs. The UG

(Cycle) CV repair program is estimated at $5.20M per year. The incremental increase in CV conditions detected during the Targeted scanning is estimated at $0.26M per year.

Total Funding Level ($000):

Incremental Change
Future Elements of Expense

EOE	Request 2020	Request 2021	Request 2022
Labor	(750)	-	-
M&S	-	-	-
A/P	3,080	3,600	(5,400)
Other	-	-	-
Total	**2,330**	**3,600**	**(5,400)**

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Actual 2018
Labor	17,397	10,191	6,555	12,128	9,750	9,110
M&S	2,036	159	403	296	318	241
A/P	47,292	27,039	29,304	22,647	21,974	22,479
Other	37	27	(76)	113	105	66
Total	**66,762**	**37,416**	**36,185**	**35,184**	**32,148**	**31,896**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	10,188	9,438	9,438	9,438	9,438
M&S	270	270	270	270	270
A/P	25,140	28,220	31,820	26,420	26,420
Other	74	74	74	74	74
Total	**35,672**	**38,002**	**41,602**	**36,202**	**36,202**

	Capital
X	O&M

2019 – Central Operations/ System & Transmission Operations

Project/Program Title	Support & Maintenance – Cybersecurity and Physical
Hyperion Project Number	N/A
Status of Project	Planning
Estimated Start Date	January 2020
Estimated Completion Date	Ongoing
Work Plan Category	Regulatory Mandated

Work Description:
License and maintain new physical and cybersecurity tools and systems necessary for the protection of the critical cyber assets and high value networks (HVN) that are housed at the Energy Control Center (ECC) and the Alternate Energy Control Center (AECC) and for adherence to regulatory requirements. Such systems are critical to the safe and reliable operation of the electric systems. They include:

- User access management systems
- Remote access management systems
- Patch management systems
- Firewall systems
- Intrusion detection and intrusion protection systems
- User behavior analysis systems
- Configuration management systems
- Malware protection tool management systems
- Security event log management systems
- Compliance management systems

Justification Summary:
System Operation relies on computers and other microprocessor based systems to operate Con Edison's electric system from its control centers. These systems run sophisticated and state of the art intelligent flow- based applications and are afforded the appropriate physical access control systems, control access management systems in order to ensure reliable and secure communications with each other, the Company's substations, neighboring utilities, and regulating entities.

It is essential that these systems remain green, capable of meeting the business needs, serviced at an accelerated basis and afforded the appropriate vendor support level, including licensing, diagnosing problems and testing patches specific vendor provided applications.

Supplemental Information:

- Alternatives:

  Do not deploy these systems.

- Risk of No Action:

Lowered cybersecurity readiness level; greater risk of violating North American Electric Reliability Corporation (NERC) cybersecurity regulations; stale systems and stale applications. Unsafe or compromised Bulk Electric System (BES) could have severe financial consequences.

- Non-financial Benefits: The systems are directly related to the safe and reliable operation of the BES.
- Summary of Financial Benefits (if applicable) and Costs: Not applicable
- Technical Evaluation/Analysis: Not applicable
  - Project Relationships (if applicable): Not applicable
  - Basis for Estimate: Current and similar maintenance contracts.

Total Funding Level ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-	-	-
M&S	-	-	-	-	-	-
A/P	1,533	1,582	1,472	1,578	1,842	1,799
Other	-	-	-	-	-	-
Overheads	-	-	-	-	-	-
Total	**1,533**	**1,582**	**1,472**	**1,578**	**1,842**	**1,799**

Request by Elements of Expense

EOE	2019 Budget	2020 Request	2021 Request	2022 Request	2023 Request
Labor	-	-	-	-	-
M&S	-	-	-	-	-
A/P	1,653	2,212	2,212	2,212	2,212
Other	-	-	-	-	-
Overheads	-	-	-	-	-
Total	**1,653**	**2,212**	**2,212**	**2,212**	**2,212**

Exhibit__(EIOP-9)

T&D Environmental

Schedule 1: T&D Environmental Capital Program and Project Summary

Electric T&D		**Year Total**			
Environmental		**Current Budget**			
		Total Dollars ($000)			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
Environmental					
Organization	**White Paper**				
Transmission	Environmental Enhancement Program	586	600	600	1,786
Distribution	Oil Minders	718	3,718	718	5,154
Transmission	Pipe Enhancement Program	25,000	25,000	25,000	75,000
Substations	Substation EH&S Risk Mitigation Program	57,100	57,100	5,000	119,200
TOTAL ELECTRIC					
	Total Environmental	**83,404**	**86,418**	**31,318**	**201,140**

Schedule 2: T&D Environmental O&M Program Change Summary

Infrastructure Investment Panel				
O&M Program Changes				
EIOP - Environmental				
($000)				
		RY1 Program Change	**RY2 Program Change**	**RY3 Program Change**
Environmental				
Organization	**Program Change**			
Substations	Substation EH&S Risk Mitigation Program	11,945	(1,449)	(10,496)
TOTAL ELECTRIC				
	Grand Total	**11,945**	**(1,449)**	**(10,496)**

**Substation EH&S Risk Mitigation White paper Associated with O&M Expenditures found in Schedule 3*

Schedule 3:

T&D Capital White papers

Environmental

X	Capital
	O&M

2019 – Central Operations/System & Transmission Operations

Project/Program Title	Environmental Enhancement Program
Project Number	Various
Hyperion Project Number	PR.22679434
Status of Project	Engineering
Estimated Start Date	Ongoing
Estimated Completion Date	NA
Work Plan Category	Strategic

Work Description:

This program will cover the installation of cathodic protection rectifiers along select High Pressure, Fluid Filled Feeders to supplement existing pipe cathodic protection. The work may include the installation of conduit, power supply connections and the installation of anodes. This program will target approximately two installations per year. Previously this program also covered the upgrade of leak warning system components in the dielectric pressurization facilities in Substations. The funding and scope for that portion of the program was transferred to Substation Operations.

Justification Summary:

Buried sections of pipe type cables are cathodically protected to prevent corrosion that can result in dielectric fluid leaks. Cathodic protection systems are comprised of a rectifier that applies DC current to the pipe surface, a protective coating to minimize the required current and Isolator Surge Protectors (ISP) to provide DC isolation between the pipe and substation ground mats. As the coating deteriorates over time and its resistance decreases, the amount of current required for effective cathodic protection needs to increase often by the replacement of existing rectifiers or the installation of new ones. In accordance with Company Procedure G-6202, Procedure for Maintaining Cathodic Protection on Electric Underground Transmission Feeders, Corrosion Control performs an annual cathodic protection survey on each electric transmission pipe-type feeder to determine if system deterioration of the pipe coating has occurred. Gas Corrosion evaluates and makes recommendations if additional cathodic protection is required. Gas Corrosion has identified areas that either need rectifier additions or rectifier replacements. These rectifiers are a critical component in protecting feeder pipes from corrosion, thereby reducing the risk of dielectric fluid leaks.

Supplemental Information:

- Alternatives: There is no applicable alternative.

- Risk of No Action: The alternative to this program is not adding rectifiers to the cathodic protection systems of these select feeder locations and to allow for a reduced protection condition. Over time, this course of action will increase the risk of pipe corrosion and may result in dielectric fluid leaks to the environment. Dielectric fluid leaks not only have an adverse impact on the environment but they can affect feeder reliability.

- Non-financial Benefits: This program will reduce the likelihood of dielectric fluid leaks which can improve environmental performance and feeder availability.

- Summary of Financial Benefits (if applicable) and Costs: Reduction of dielectric fluid leaks would reduce leak response and pipe repair costs to the company

- Technical Evaluation/Analysis: See Justification Summary and Alternatives above.

- Project Relationships (if applicable): N/A

- Basis for Estimate: An engineer's estimate was used as the basis for funding in this program for the years 2018-2023.

Annual Funding Levels ($000):

Historic Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	217	110	58	23		23
M&S	4	11	18	10		10
A/P	124	146	162	224		98
Other	-	1	2	-		-
Overheads	250	179	99	71		80
Total	**595**	**447**	**339**	**328**		**211**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	113	163	163	206	208
M&S	212	142	142	117	117
A/P	53	74	74	204	204
Other	25	17	17	36	37
Overheads	78	190	204	38	34
Total	**481**	**586**	**600**	**600**	**600**

X	Capital
	O&M

2020 – Electrical Operations

Project/Program Title	Oil Minders
Project Manager	Jane Shin
Hyperion Project Number	PR.5ED0121, PR.5ED4131, PR.5ED1151, PR.5ED3141, PR.5ED7121
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
This program provides funding for the installation of oil minders in underground network transformer vaults. The Oil Minder program was developed to prevent the pumped discharge of dielectric fluid from network transformers into the sewer system. An oil minder senses oil in water and disables the associated sump pump to prevent the discharge of oil. The oil minder control system registers an alarm in the local control room through the Remote Monitoring System (RMS) whenever the oil minder operates. This remote warning signal facilitates early detection and cleanup of leaking dielectric fluid.

The Company forecasts a rate of 75-100 new oil minder installations per year. At time of oil minder installation, any defective sump pumps will be replaced as well.

Justification Summary:
This program complies with a 1997 a commitment made by the Company to the New York State Department of Environmental Conservation (DEC) to address dielectric fluid leakage from underground transformers. The oil minder program has been effective at intercepting oil before it enters the sewer system.

Supplemental Information:

- Alternatives:
  An alternative would be to operate vaults without pumps and allow water to collect. Such a design would require the use of submersible equipment in all transformer vaults and would be significantly more costly than using ventilated equipment with a sump pump.

- Risk of No Action:
  Without the presence of oil minders, there is a substantial risk of releasing oil into the sewer system.

- Non-financial Benefits:
  Oil released in a transformer vault is an indicator of transformer failure. The oil minder and alarm provide early indication of transformer failure and allow operators to investigate the problem and prior to failure. This ability to intervene has implications to system reliability, quality of service, public safety and environmental impact.

- Summary of Financial Benefits (if applicable) and Costs:
  Reducing the water levels in our vaults reduces rust and corrosion of the transformers and network protector switches and increases service life.

- Technical Evaluation/Analysis:
  The oil minder has undergone several durability changes to improve their capability to withstand the conditions of the underground transformer vaults. A power sensor device was added to send an RMS signal to notify operators of a power failure to the oil minder & sump pump. The power sensing feature helps prevent damage to the equipment and reduces costs.

- Project Relationships (if applicable): None

- Basis for Estimate:
  Historical unit costs

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	295	464	1,921	1,345		304
M&S	108	554	1,682	1,636		992
A/P	30	22	1,138	405		-
Other	(38)	(81)	(2,306)	(2,110)		-
Overheads	277	597	2,095	1,451		456
Total	**672**	**1,556**	**4,530**	**2,727**		**1,752**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	487	159	859	142	144
M&S	74	24	119	19	19
A/P	112	31	168	27	27
Other	512w	316	1,641	354	351
Overheads	561	188	931	176	177
Total	**1,746**	**718**	**3,718**	**718**	**718**

X	Capital
	O&M

2019 – Central Operations/System & Transmission Operations

Project/Program Title	Pipe Enhancement Program
Project Manager	Mark Bauer
Hyperion Project Number	PR.22679502
Project Number	Various
Status of Project	Construction
Estimated Start Date	On-going
Estimated Completion Date	NA
Work Plan Category	Strategic

Work Description:
The Pipe Enhancement Program is a proactive program to reduce dielectric fluid leaks and increase the availability of transmission facilities. This program focuses on addressing areas of corrosion on the pipe-type transmission feeder system and involves the large-scale installation of welded barrels to encase heavily corroded areas and the installation of new coating, along with the associated required excavation, coating removal, inspection, and backfill/restoration tasks (Note: The coating removal and pipe inspection tasks are charged to operation and maintenance expense.). This program will provide increased reliability, extend the useful life of existing pipe-type feeder facilities, and prevent or reduce the likelihood of the release of dielectric fluid from the pipe-type feeder system to the environment.

Suspect areas of feeder pipe were originally identified based on leak history data and field observations of pipe/coating conditions during maintenance work. More recently, close interval surveys (cathodic protection measurement surveys) and keyhole inspections (small exploratory excavations) have been performed to determine areas of suspect coating conditions. Large areas of disbonded coating (where the existing coal tar coating is not necessarily missing but may be cracked and poorly adhered to the exterior surface of the pipe) have been identified as a significant issue for certain critical pipe-type feeders. Disbonded coating allows moisture to migrate onto the pipe surface beneath the coating. In addition, disbonded coating shields the flow of cathodic protection current, preventing it from reaching the surface of the pipe. As a result, severe corrosion can occur beneath the coating, causing significant pipe wall loss and dielectric fluid leaks.

Dielectric fluid leaks can result in feeders being removed from service if the leak rate exceeds the flow rate capability of the pressurization pumps. If a leaking feeder was left in service and operating pressure could not be maintained, failure of the cable system can result, requiring an extended outage to complete repairs. In addition, even if pressure can be maintained, a feeder with a large leak may be forced out of service in order to clamp and repair the leak if the release of fluid cannot be adequately controlled during the repair process. These issues can have detrimental effects on overall system reliability, especially during high load periods.

If feeder pipe conditions are allowed to deteriorate due to disbonded coating or other corrosion-related issues to the point where significant wall loss has occurred over large portions of a feeder, a pattern of repeated, large volume leaks can be anticipated. At some point, these leaks will greatly diminish feeder reliability and effectively limit the feeder’s useful life. To proactively prevent this condition, the Pipe Enhancement Program addresses large-scale coating problems to eliminate future corrosion, as well as restores pipe wall thickness in already deteriorated areas. This is accomplished by encapsulating areas of wall loss with a new layer of pipe welded over the original pipe, over its full circumference (if needed), and coating that surface with a new protective coating system. More recently, a new technology has been tested and applied called Carbon Fiber Wrap (CFW,) which is a refurbishment method where several layers of a carbon fiber fabric saturated with epoxy are overlapped on the existing deteriorated pipe to form a composite shell. In effect, the corroded pipe is "replaced" without removing the old pipe, which of course could not be done without affecting the energized feeder cables inside. The composite wrapping becomes the new pressure boundary layer in place of the original steel pipe. While this method is significantly more costly than the conventional method of refurbishment using individual welded steel reinforcement patches or sleeves, this method is now being utilized where longer continuous lengths of pipe are severely deteriorated and where the conventional refurbishment method is not logistically favorable. The CFW method is expected to greatly extend the lifecycle for some of the feeder pipe areas that were the most difficult to address using the conventional method.

Mitigation of the release of dielectric fluid to the environment is a critical component of the Company's efforts to achieve environmental excellence. The Company sets an annual goal to minimize the volume of dielectric fluid released to the environment from the pipe-type feeder system and tracks the actual volume against this goal each month. The Pipe Enhancement Program will help to establish a trend of significantly reducing the dielectric fluid volume loss to the environment as the most suspect sections of pipe on the Transmission System are proactively addressed.

Justification Summary:
This Pipe Enhancement Program will result in a reduction of the number of leaks. By addressing corrosion issues before the pipe leaks occur, Con Edison will be able to reduce the amount of dielectric fluid that is lost to the environment and the associated costs for leak emergency response and remediation. The program also reduces the probability that the feeder will need to be removed from service or fail due to an oil leak caused by corrosion on the pipe.

Current Status: The Pipe Enhancement Program is an on-going annual program. Work packages appropriated under this program to date have focused on suspect areas of Feeders M51, M52 since they contribute the highest percentage of dielectric fluid lost to the environment of any feeders on the Con Edison Transmission System. The Company will focus a large majority of this program's funding in 2019 on enhancing the Harlem River Drive portion of M51 and M52 with CFW and other remaining targeted suspect areas of feeders M51, M52 by 2020. In future years, work will focus on other candidate areas addressing emergent areas on other feeders displaying a significant pattern of leaks.
Based on the continued findings of the completed, ongoing, and planned Pipe Enhancement Program work packages, the Close Interval Survey results, and visual inspection of the pipe coating through Keyhole Excavations, locations to perform Pipe Enhancement Program will be prioritized.

Supplemental Information:

- Alternatives: Although the Research and Development (R&D) Department has conducted benchmarking of other companies, and Con Edison continues to participate in EPRI and NACE studies, to date the Company has found no other proactive alternatives available to address the corrosion issues on transmission feeder pipes. R&D continues to pursue initiatives related to pinpointing specific areas of disbonded coating, but at this time no viable alternative exists to effectively address corrosion due to disbonded coating other than large-scale refurbishment of the pipe through the Pipe Enhancement Program.

- Risk of No Action: Not addressing sections of deteriorated pipe will, over time, result in increased loss of dielectric fluid to the environment due to feeder pipe leaks and increased spending in the area of feeder emergencies. In addition, if the loss of dielectric fluid is severe enough, feeders may have to be removed from service while leaks are located and repaired.

- Non-financial Benefits: Protection of the environment, increased reliability, and extension of the useful life of the pipe-type feeder system are all significant non-financial benefits. In addition, building better key external stakeholder relationships with organizations such as the DEP, DEC, and PSC is another major non-financial benefit.

- Summary of Financial Benefits (if applicable) and Costs: Not applicable.

- Technical Evaluation/Analysis: As discussed, large areas of disbonded coating (where the existing coal tar coating is not necessarily missing but may be cracked and poorly adhered to the exterior surface of the pipe) have been identified as a significant issue for certain critical pipe-type feeders. Disbonded coating allows moisture to migrate onto the pipe surface beneath the coating. In addition, disbonded coating shields the flow of cathodic protection current, preventing it from reaching the surface of the pipe. As a result, severe corrosion can occur beneath the coating, causing significant pipe wall loss and dielectric fluid leaks. Further, studies have shown that paper-insulated pipe-type transmission cable has an exceptionally long life if proper pressurization is consistently maintained. Pressure excursions due to repeated, significant leaks may also impact cable life. The duration a cable is in service at pressures below the minimum specified operating pressure will adversely affect the useful life of the cable once the voltage stresses exceed the capability of the insulating system to withstand them. As pressure on a pipe-type feeder system decreases, the insulating capability of the system decreases and ionization (and eventual electrical breakdown) of the paper insulation can result. Even if a specific leak incident does not result in immediate failure of the cable, the long-term effective life of the cable may be reduced.

- Project Relationships (if applicable): Not applicable.

- Basis for Estimate: The historical costs (in dollars per trench foot) for pipe enhancement were used to project funding levels for this program. Based on historical spending levels, the projected cost for the work was $5,667 per trench foot and this cost was used to determine funding levels to complete 6,744 trench feet in 2016. In 2017, 7,737 trench feet was completed at a cost of $38.2M. The estimated cost for CFW is estimated to be on the order of $14K per trench foot.

Total Funding Level ($000):

Historical Elements of Expense

(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	782	838	1,446	4,393		7,290
M&S	240	177	465	1,439		1,515
A/P	2,757	2,505	6,008	20,777		27,005
Other	643	174	$98	266		70
Overheads	3,890	4,319	7,852	17,023		10,120
Total	**8,170**	**15,870**	**43,989**	**38,187**		**46,000**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	5,388	3,222	3,222	3,222	3,222
M&S	1,245	594	594	594	594
A/P	21,499	12,842	12,842	12,842	12,842
Other	2,194	1,525	1,628	1,734	1,625
Overheads	9,674	6,817	6,714	6,608	6,717
Total	**40,000**	**25,000**	**25,000**	**25,000**	**25,000**

X	Capital
X	O&M

2019– Central Operations / Substation Operations

Project/Program Title	Substation EH&S Risk Mitigation Program.
Project Manager	John McCoy
Hyperion Project Number	PR.2ES8900
Status of Project	In-Progress
Estimated Start Date	N/A
Estimated Completion Date	N/A
Work Plan Category	Regulatory Mandated

Work Description:

Operational enhancements and site improvements, such as modifications to secondary containment structures around oil filled equipment, installation of oil/water separator (OWS) systems, and site drainage upgrades, are planned at several locations, many of which are required by federal regulations.

These projects are required to manage and mitigate the risks of a potential oil release to the environment, and to address regulatory requirements and ensure the health and safety of the public and employees. The majority of the work is completed or planned in conjunction with the required 5 year review of the applicable secondary Spill Prevention Control and Counter Measures Spill Prevention Control and Counter measures (SPCC) plans.

During the failure of Transformer #3 at Farragut Substation in 2017, the main tank ruptured resulting in the release of dielectric fluid onto the adjacent bluestone. A portion of the dielectric fluid from the failed transformer leaked into the ground and ultimately reached the East River. After a thorough internal review, the Company outlined a strategy to transition from site containment to unit containment for all large power transformers, phase angle regulators and reactors. Subsequently, the company will be evaluating other oil containing equipment in the substation in a further effort to reduce the risk of oil leaving a substation and getting into the environment.

Justification Summary:

These projects are needed to establish system-wide unit containment of all oil-filled equipment. This will mitigate risks associated with potential oil release to the environment from substation equipment. Effective risk management is critical to ensuring good environmental stewardship and the health and safety of the public and our employees. Equipment in substations is evaluated for potential environmental impacts, particularly an uncontrolled oil release to the environment, during normal and abnormal conditions. Installation and modifications to stations' containment and drainage systems to manage the water discharges and runoff as well as potential oil releases are being implemented as needed to mitigate the risks identified during these evaluations. These projects are also required to ensure compliance with regulatory requirements such as Spill Prevention Control and Counter measures (SPCC) 40CFR112 and New York Department of Environmental Conservation (DEC) State Pollutant Discharge Elimination System (SPDES).The operations and maintenance expense portion of this project includes the below-ground interconnection and installation of flame arrestors between existing transformer moats.

Supplemental Information:

- Alternatives: The majority of the work done via this program is the result of independent third party reviews of the Company's Spill Prevention Control and Counter Measures (SPCC) plans at various stations. These reviews evaluate if there are spill risks that may not be adequately addressed, and could impact the environment. Each issue raised as part of the reviews is then addressed. Cost effective alternatives for each issue are evaluated during the design and engineering of each of the projects. Solutions such as berms, moats, oil water separators, etc. are all evaluated and then the least cost effective options are chosen for each specific project.

- Risk of No Action: No action is not recommended since these projects are required to manage and reduce the risks associated with potential impacts to the environment and the health and safety of the public and employees. In addition, many of these projects are needed to ensure compliance with Spill Prevention Control and Counter Measures SPCC regulatory requirements.

- Non-financial Benefits: These projects reduce or eliminate the risk of oil leaving substation property or getting into the environment, reducing environmental impact and fostering better community relations.

- Summary of Financial Benefits (if applicable) and Costs: This program ensures compliance with regulations and prevents the likelihood the Company may be fined for non-compliance with NYSDEC requirements pursuant to oil spills.
- Technical Evaluation/Analysis: Central Engineering coordinates extensive evaluations of the site containment and storm water drainage systems at all substations. These studies are performed to better evaluate and address the potential risks of an offsite oil release.

- Project Relationships (if applicable): Containment required facilitating EH&S Risk Mitigation projects were coordinated with storm hardening efforts at multiple substations. It is expected storm hardening efforts (i.e., perimeter walls) at a number of substations will likely reduce or eliminate the need to install additional SPCC measures.

- Basis for Estimate: Near term work based on Engineering estimates. Outer term work based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature. Future funding requests assume all known regulatory required work will be completed by 2020.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	2,814	1,695	986	421		3,675
M&S	876	289	108	200		681
A/P	5,554	3,006	1,949	3,000		13,777
Other	265	(362)	22	86		245
Overheads	5,391	3,210	1,362	862		5,467
Total	**14,900**	**7,838**	**4,427**	**4,570**	**-**	**3,846**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	8,140	11,135	11,135	1,000	2,600
M&S	1,831	2,284	2,284	200	520
A/P	18,279	24,667	24,920	2,150	5,535
Other	1,211	1,483	1,484	150	390
Overheads	11239	17,531	17,277	1,500	3,955
Total	**40,700**	**57,100**	**57,100**	**5,000**	**13,000**

O & M Future Elements of Expense:

	Request 2020	Request 2021	Request 2022
O&M expense	11,900	10,500	-

Exhibit__(EIOP-10)

T&D Information Technology

Schedule 1: T&D Information Technology Capital Program and Project Summary

Electric T&D		**Year Total**			
Information Technology		**Current Budget**			
		Total Dollars ($000)			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
Information Technology					
Organization	**White Paper**				
Substations	AutoCad	500	700	1,000	2,200
Substations	Construction--Survey mapping	520	520	520	1,560
Distribution	CPMS Customer Knowledge Self Service	3,000	3,000	3,000	9,000
Distribution	DECC Alarm Manager	250	250	250	750
Transmission	District Operator Task Management	390	400	400	1,190
Distribution	Distribution Ops Training Simulator	250	150	150	550
Transmission	Distribution Order Enhancements	293	300	300	893
Distribution	Electric Distribution SCADA Enhancement*	1,200	2,200	1,000	4,400
Distribution	Electronic Feeder Sign On	351	351	351	1,053
Distribution	Emerging IT	3,823	11,272	10,000	25,095
Transmission	EMS Replacement AECC And ECC	4,684	-	-	4,684
Substations	Field Smart Forms	250	250	250	750
Distribution	Integrate Machine Learning Models-CAP	250	250	250	750
Distribution	Outage Management System IT System Hardening**	10,000	10,000	5,000	25,000
Transmission	Operation Management System Enhancements	390	400	400	1,190
Transmission	OSS Phase 3	2,752	-	-	2,752
Distribution	Outage Management System- Phase 3&4	2,500	2,500	1,750	6,750
Transmission	Plant Information System	-	-	250	250
Substations	Rogue Employee (GRC)	200	200	200	600
Substations	Substation Technology Improvements Program	1,100	2,000	2,000	5,100
Transmission	System Operation Enhancements	293	300	400	993
Distribution	Work Management System Sustainability	3,000	3,000	3,000	9,000
Distribution	WMS-Phase II & Enhancements	7,240	-	-	7,240
TOTAL ELECTRIC					
	Total Information Technology	**43,236**	**38,043**	**30,471**	**111,750**

**Electric Distribution SCADA Enhancement White Paper Associated with O&M Expenditure found in Exhibit__(EIOP-5) Schedule 4*

***Outage Management System IT Hardening White Paper Associated with O&M Expenditure found in Exhibit__(EIOP-5) Schedule 4*

Schedule 2: T&D Information Technology O&M Program Change Summary

Infrastructure Investment Panel				
O&M Program Changes				
EIOP - Information Technology				
($000)				
		RY1 Program Change	**RY2 Program Change**	**RY3 Program Change**
Environmental				
Organization	**Program Change**			
Transmission	OSS Maintenance	237	-	-
TOTAL ELECTRIC				
	Grand Total	**237**	**-**	**-**

Schedule 3:

T&D Capital White Papers

Information Technology

X	Capital
	O&M

2019 – Central Operations/Common

Project/Program Title	AutoCAD (Engineering Equipment Upgrade Program
Project Manager	Robert Burke
Hyperion Project Number	PR.20355460
Status of Project	Ongoing
Estimated Start Date	NA
Estimated Completion Date	December 2022
Work Plan Category	Operationally Required

Work Description:
This program will make software and hardware upgrades to the Computer Aided Design (CAD) Program that is used in Central Engineering for design work. This program covers licensing for the software and will also upgrade or replace plotters, scanners, CAD workstations that are utilized in design.

Justification Summary:
Design is an essential component of the ability to engineering construction projects for the Company AutoCAD is the primary drawing tool used by designers in Central Engineering. Making periodic upgrades and replacements of AutoCAD software and hardware enables Central Engineering to maintain a productive design process. It is essential that AutoCAD be kept operation and current with industry standards.

Supplemental Information:

- Alternatives: The only alternative to this program would be to find or develop another software package for design work. This alternative would require high initial fixed costs and re-training of Company personnel.

- Risk of No Action: No action would result in the CAD software and hardware to become obsolete and unusable/incompatible. This would create risk of not maintaining accurate engineering drawings for our assets and not performing capital projects on a timely basis due to inability to produce drawings to support the work.

- Non-Financial Benefits: Providing designers with upgraded, up-to-date, software and hardware provides workplace efficiency and contributes to employee satisfaction

- Summary of Financial Benefits (if applicable) and Costs: This program seeks to consolidate the remainder of our corporate licenses over the next several years. Doing so will allow us to take advantage of concurrent licensing and reduce our overall corporate spend on CAD licenses from approximately $400k to $200k annually.

- Technical Evaluation/Analysis: This program funds the purchase of CAD software and hardware. Prior to purchase, analysts perform a thorough technical evaluation on available options ensuring ability to meet business needs both in the present and projected needs in the near future.

- Project Relationships (if applicable): None.

- Basis for Estimate: The funding request for this program is based on past costs and projected future needs

Total Funding Level ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Request by Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	-	-	-	-	-
A/P	-	-	-	-	-
Other	-	-	-	-	-
Overheads	-	-	-	-	-
Total	**1,100**	**500**	**700**	**1,000**	**500**

X	Capital
	O&M

2020 – Construction

Project/Program Title	Construction - Survey Mapping Repository
Project Manager	Robert Davis / Leonard Burshtein
Project Number	PN.20782709
Status of Project	Ongoing
Estimated Start Date	01/2012
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
Implement a Survey Mapping Repository for the electronic storage of Survey field data to make it available for the mapping of Company assets, structures and field survey data. This will make a wealth of digital Survey information available across departments.

The Survey Department performs work for the following groups:
- Electric Operations
- Gas Operations
- Steam Operations
- Transmission Operations
- Substations Operations

A sample of Survey data to be archived for future use includes:
- Survey of Transmission Towers, Substations, and Underground Transmission Feeders
- Substations 3D Laser Scanning
- Distribution Engineering - Poles and Manholes
- Gas Leaks Survey
- Gas Facilities Inventory
- Gas Aerial Photography

Some of the benefits of implementing a survey mapping repository are:
-Establishment of digital landscape of all survey activity
-Reduce Test Pits Requests (data stored and retrievable)
-Feed to Asset Management System
-Interaction with New York City GIS
- Interaction with New York State GIS
-Ability to display Wetlands, Tax, Parcel Data, and Paving Schedules
-Will facilitate review and optimization of the Construction Survey

Note this may include miscellaneous hardware purchases to be used by the Construction Organization

This implementation will include Microsoft's SQL Database server with the full ESRI Suite of Mapping products. This is the same platform used by New York City, New York State and Information Resources.

Justification Summary:
This new system will enable Construction to share Survey field information with other CECONY organizations. Survey will catalog the information in order to provide an indexed repository of all work performed. This information will be viewable by end users. This will provide a real time visual representation of work being performed and will lower reproduction costs and the number of Survey requests for redundant information.

This will enable users to visualize survey grade information on real time, coordinate-based information for Company assets.

Supplemental Information:

- Alternatives: Continue to store information locally.

- Risk of No Action: The Construction Survey group will need to stop digital electronic surveying since there will be no place to store and retrieve the data. Survey Department will not be able to take advantage of the current electronic asset repository. This highly sensitive information will be kept in paper files with cumbersome methods for retrieval analysis and audits.

- Non-financial Benefits: The system will render 3D Survey grade and GPS mapped representation of assets added to the CECONY network. This will enable better location of structures for mark outs and maintenance work.

- Summary of Financial Benefits (if applicable) and Costs:
  These enhancements will reduce redundant request for surveys of areas. The information is being stored for use by multiple commodities via the spatial mapping platform.

- Technical Evaluation/Analysis:
  The platform and approach were reviewed. The project is adhering to the current corporate standards and architecture

- Project Relationships (if applicable): Enterprise Mapping, Work Management

- Basis for Estimate:
  Historical costs for this type of project.

Total Funding Level ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	-	-	-	-	-
A/P	-	-	-	-	-
Other	-	-	-	-	-
Overheads	-	-	-	-	-
Total	**-**	**520**	**520**	**520**	**-**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	CPMS Customer Knowledge Self-Service
Project Manager	Richard Brown
Hyperion Project Number	PR.23494453
Status of Project	In Progress
Estimated Start Date	01/01/2019
Estimated Completion Date	12/31/2022
Work Plan Category	Strategic

Work Description

This project is a part of Energy Services Department's strategic plan to improve its business operation. The initial implementation included a new Customer Project Management System (CPMS) that went live in 2013. The project was a significant step in streamlining and refining a number of internal processes. The second major implementation (CPMS2) focused on enhancing customer-facing interactions including self-service scheduling of inspection appointments, new mobile functionality for customers to accomplish a number of case-related tasks using a cell phone, a new customer inquiry feature to manage and track customer questions, and new analytic tools.

Evolving customer expectations have continued to trend toward self-service, flexibility, 24/7 availability, machine learning, transparency, and customer control. The proposed project, Customer Knowledge Self Service (CKSS) seeks to further enhance the customer experience by introducing a new generation of self-service functionality and self-help tools. The end goals are to dramatically reduce external customer phone calls to internal representatives, and to increase customer satisfaction by delivering the information they need to progress their case at the moment they need it. Ultimately, the objective is to anticipate questions and identify potential problems even before they occur and to provide appropriate and accurate information before customers realize they need it. This project will implement a scalable, simple, customer centric experience comparable to experiences that customer have at Uber, Facebook, Google and Amazon.

The Customer Knowledge Self Service project plans to add the following functional capacities:

Omni Channel Communications

Omni Channel Communication aggregates all customer interactions – whether they are via email, phone, text, mobile app, etc. – into a single stream of content. All customer interaction "channels" will be managed by a single customer interaction "layer" in the current case management platform.

Index Management Crawler (IMC)

Index management makes documents in network repositories such as SharePoint available for search and classification. A crawler actively collects resource documents (internal and external) into a hierarchical structure which then populates the index when a search is conducted. Although some indexing does currently occur with SharePoint, this feature would allow for a more robust search capability similar to Google (often called "fuzzy search"). This functionality will be accompanied by Alert and Notification features that will ensure users (internal and external) are made aware of when a document has been updated or removed, including:

- Engineering specs (internal and external)
- Blue Book and Yellow Book (internal and external)
- Customer Service Procedures (internal)

Customer "knowledge" would also include case related data (such as "What is the deposit on my case and when is it due?").

Answer Bots (aka Automated Response Bot, Email Bot)
Answer Bots are designed to automate tasks that humans routinely do, such as reading incoming customer emails, determining the content of the email, and providing an appropriate response. These tasks can now be performed by (ro)bots. For example, a bot can scan an incoming email, determine that the email contains a question regarding an inspection appointment, and can respond by providing appointment information and status (time and date), a link to the customer portal (Project Center) Online Calendar, and links to the relevant FAQs and job aids. When a bot comes across a question that it has difficulty responding to, the bot can route the email to an appropriate human representative and can provide an alert within the case. Email bots are programmed to recognize natural language to determine the intent of the customer's question and is more accurate than typical keyword search technology.

Chat Bot
Chat Bots are an artificial conversational entity that engages the customer as the first line of response before human intervention is required. These programs start with a request by the customer for a Chat Session and begin with a small talk algorithm that provides the customer with a human-like interaction, providing responses to simple questions and escalating more difficult questions to a human rep for further interaction.

Machine Learning/Artificial Intelligence
Artificial Intelligence (AI) technology is used to manage and measure auto responses provided by bots. AI technology can determine whether the bot has a sufficient level of "confidence" that it can provide an accurate auto response before sending it to a customer, and if not, will make the decision to route the question to a human representative.

If an auto response fails to adequately answer an inquiry, the system will "learn" to provide a more accurate answer through feedback loops built into the system. This AI component is called "machine learning" and is increasingly becoming part of self-service technologies in every industry.

Justification Summary:
The total estimated project cost for the follow-on phases that includes build, testing, and deployment of the Customer Knowledge Self Service (CKSS) project is approximately $12M, including appropriate contingencies. The estimated duration of CKSS is 4 years, starting in January, 2019 and completing in December, 2022.

PHASE 0

A Phase 0 project is underway and will consist of a fit/gap analysis of each functional technology noted above. It will define the related business requirements and use cases through a series of structured workshops, develop detailed designs, and prepare detailed implementation plans for the build, testing, and deployment. Phase 0 will focus on identifying 'best-in-class' methodologies, processes and technologies for implementing knowledge management to serve our internal workers and our external customers. The initiative will identify gaps in critical knowledge assets related to the key steps in our service delivery workflows. In addition, the Phase 0 analysis will result in a multi-phase Implementation Roadmap (4 years), quick-win use cases, a cost benefit analysis, and metrics used to show on-going ROI and business value.

The Implementation Roadmap will provide detailed functional requirements to begin immediate development on the quick win use cases (Phase 1). Depending on the dollar value of each phase, a competitive bid process may be followed. This involves RFP preparation, RFP administration, and Vendor selection and mobilization.

Each phase will include required prerequisite work (analysis and design) followed by the RFP process and vendor selection. The Build, Testing, and Deployment phases will commence after vendor mobilization.

Supplemental Information

- Alternatives:
  - Continue to use the system as deployed with limited customer self-service capabilities.
  - Rely on phone, email and Customer Inquiry interactions with customers.
  - Modify the customer portal (Project Center)

  Without these new functional capabilities, Energy Services staff will continue with the existing processes of responding to customer needs and inquiries. The existing methods and processes are extremely resource dependent and routinely lead to backlogs, substantial delay and inconsistencies. This in turn could increase customer frustration and cause a negative view of Con Edison.

- Risk of No Action:
  - Energy Services staff will continue with the existing manual and resource intensive processes of responding to customer needs and inquiries.
  - Additional staffing may be required to accommodate the annual caseload increase (19% annually over the past three years).
  - Managers will not be able to re-allocate resources that could be freed up from performing routine tasks that customer self-service could provide in order to perform more complex and urgent tasks.
  - Continue phone- and email-intensive interactions between Energy Services and customers, which does not align with two of the company's main business imperatives: cost management and customer satisfaction.
  - Miss the opportunity to provide, monitor and measure responses to customer inquiries to ensure consistent, accurate answers.
  - Lose 'tribal' knowledge as long term employees retire or move on to new positions.
  - Continue to rely on standard tools and data base extractions that are extremely time consuming and inaccurate for analyzing customer data and statistics. This data is critical to identify changing trends in the business.
  - Fail to meet evolving customer expectations for intuitive self-service options.

- Summary of Financial Benefits and Costs:
  - The introduction of the identified technologies will provide an opportunity to operate more efficiently and create value for the customers we serve and their contractors (e.g., electricians and plumbers).
  - It is expected that by Year 2 of the implementation, ESD will reduce current headcount by 2 per year for 5 years for a total of 10 FTEs while maintaining current case load level increases (19% year-over-year) and customer satisfaction levels (>85%).

- Non-financial Benefits:
  - Implementation of the CKSS is expected to provide substantial increase in customer satisfaction by providing the information customers normally require from a live agent in a self-service environment.
  - Consistency, accuracy and speed in responding to customer needs and inquiries will reduce customer frustration and improve the image of Con Edison.
  - Capturing and retaining knowledge from highly-experienced employees into a database will ensure business continuity.

- Technical Evaluation/Analysis:
  - CKSS functionality will be based on commercial technology platforms that are used by leading edge companies. It will leverage the latest software, database and server technologies and include improved workflow functionality and interfaces to customer service and work management systems.
  - The design will allow scalability so that it could evolve into an enterprise solution.
  - All customer-facing technologies will be designed within the guidelines of IT and the DCX initiative.
  - The Company expects the use of the CKSS case management solution to ensure compliance with PSC incentive goals and improve overall customer satisfaction.
- Project Relationships (if applicable):
  - The project will be designed to integrate with all related current technology initiatives including DCX, CSS, GWAM, AMI, REV, etc. The extended project team includes representative from each of these initiatives.
  - The CKSS project team will continually seek to identify opportunities for partnerships with other departments searching for a similar solution.

- Basis for Estimate:
  - This request is based on the cost to build, test and deploy the CKSS project designs and includes the following:
    - Omni Channel Communications
    - Index Management Crawler
    - Advanced Search
    - Email Bots
    - Chat Bots
    - Machine Learning/Artificial Intelligence

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	91	90	90	90	-
M&S	-	-	-	-	-
A/P	763	2,491	2,359	2,234	-
Other	68	211	209	198	-
Overheads	78	198	341	477	-
Total	**1,000**	**3,000**	**3,000**	**3,000**	**-**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	DECC Alarm Manager and Analytics System
Project Manager	Maggie Chow & David Pearce
Hyperion Project Number	PR.21546534
Status of Project	In Progress
Estimated Start Date	On Going
Estimated Completion Date	12/2023
Work Plan Category	Strategic

Work Description:
The Regional Distribution Electric Control Centers (DECC) currently employ an application to monitor and alarm network and non-network remote terminal unit (RTU) data, called the Alarm Manager. This application provides visual and audible alarms for changes of distribution assets. It is an interface for Electric Control Center operators to be alerted to feeder operations and transformer related data feeds from VMS Data Acquisition Monitoring System (VDAMS). It also acts as a trigger for some system analysis applications to run, such as the real-time load-flow application. User feedback of the current system indicates that this application is not usable in its current state. The frequency and validity of many alarms, based on old logic, makes responding to every occurrence presented by the existing application untenable.

Currently there is a continuous flow of alarms within the Electric Operations control centers. Alarms are numerous, often redundant, and repetitive in nature. This leads to Alarm Fatigue, which is the de-sensitizing of operations personnel. This Human Performance Improvement (HPI) trap is negatively impacting the ability to immediately recognize the highest priority alarms and to efficiently respond with the required actions. Based on a study by SA Technologies, the existing presentation of alarms leads to Misplaced Salience which essentially is the loss of focus on key indications amid the many notifications.

This project will analyze and model the current alarm management process and develop a more efficient holistic principle of alarm management and model going forward. The resultant model will have the added functionality and provide a decision support engine interfaced with automated data sources. Based on the available input the support engine would analyze the alarm inputs to present the actionable items in order of priority.

This project will develop an application that will have the following functionalities:

- Enhanced alarm response model
- A Decision support Engine
- Provide automated data inputs.

Justification Summary:
The DECC Alarm Manager Project will be a complete re-architecture of the existing application, to address several deficiencies which currently exist. These deficiencies include: (a) No intelligence and alarm analysis capability; (2) No use of a database to utilize relational data; (3) Antiquated user interface,

yielding poor user experience; (4) Lack of alarm confirmation and appropriate logic; (5) Lack of multi-systems integration to promote automatic analysis of system events. This integration will include CDMS (VDAMS), USA, Realflex, HTMDAS, STAR, and any future data acquisition, or operational system.

This re-architecture is critical to having a usable and interactive alert system, which will increase productivity, decrease outage times by minimizing false and repetitive alarms, and enable the integration of multiple systems for outage event profiling.

Supplemental Information:

- Alternatives: Continue to operate with current alarm manager limitations and inherent issues with data presentation and interaction with operators.

- Risk of No Action:
    - The current Alarm Manager is not suitable for the existing data acquisition systems. There are many false alerts.
    - Due to lack of alert filters and appropriate logic, the existing Alarm Manager causes real alerts to be missed, and false alerts to overwhelm operators.
    - The existing Alarm Manager has limited ability to interface with other applications (mapping, etc.), to create an event profile to be presented to the operator.

- Non-financial Benefits: Enhanced productivity and efficiency of control center personnel in responding to system emergencies.

- Summary of Financial Benefits and Costs: The completion of this project helps to minimize the possibility of a network shutdown due to more effective operation and management of the alarms associated with the operation of networks. Benefits include avoiding costly penalties such as the existing **Reliability Performance Mechanism (**RPM) revenue adjustment of $10 million incurred for each network shutdown.

- Technical Evaluation/Analysis: Technical evaluation/analysis to be completed during POC phase.
- Project Relationships (if applicable): N/A

- Basis for Estimate: Labor figures below assume $100/hr contractor FTE costs based on prior resources meeting similar SCADA experience requirements. Hardware costs are estimated based on a requirement of 1 HA server installation at $50k per site for 4 production Distribution Control Centers. Software license costs are estimated based on prior software purchases capable of accommodating the distribution electric asset count.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	16	48		-
Other	-	-	18	10		-
Overheads	-	-	1	1		-
Total	**-**	**-**	**35**	**59**		**-**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	112	105	106	105	105
M&S	-	-	-	-	-
A/P	78	87	86	87	87
Other	7	8	8	8	8
Overheads	54	50	50	50	50
Total	**251**	**249**	**250**	**249**	**249**

X	Capital
	O&M

2019 Capital - Central Operations/System & Transmission Operation

Project/Program Title	District Operator Task Management
Project Manager	Richard Scholz
Hyperion Project Number	PR.21925935
Status of Project	Ongoing
Estimated Start Date	January 1998
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

This project will enhance the issuance and the tracking of status changes of the electric distribution and transmission systems operating orders. The Task Management system will provide the District Operators with a timely and integrated view of all jobs within their specific jurisdiction and with application oversight and reports to help in providing timely response to work orders throughout all phases.

The new software functionality includes computerized warnings and other indications that will contribute to timely processing and error free environment. New operator consoles will be added to support these new applications. The new 3G Feeder Networks will be modeled and integrated into the electronic order flow which the current system does not allow for. The interfaces with Rapid Restore, FeederBoard and Visual Electronic Distribution Information System (VDIS) will be updated to reflect the changes in 3G field conditions and connections.

Justification Summary:

The District Operators coordinates and directs all switching operations on Con Edison's distribution and transmission systems using multiple computer systems including the energy management system (EMS), Feeder Management System (FMS), Transmission Operation Management System (TOMS), Telephone Line System (TLS), and other corporate systems such as Rapid Restore, DO Direct, Outage Scheduling System (OSS). Each of these systems has different user interface and operates on different vendor platforms and operating systems.

This project will enhance the operators' environment by allowing them to perform their important tasks from a common graphical interface and manage the varied and multiple systems more efficiently.

Supplemental Information:

- Alternatives: None. Maintaining the current interfaces will not model the 3G Feeder Networks nor allow for the integration of the multiple systems.

- Risk of No Action: Without continuous system improvement and the addition of new functionality, the OMS systems would not allow the District Operators to safely direct the outage maintenance of the electric grid. Keeping current with physical changes to the distribution system and procedural processes in the field, is critical in maintaining the reliability of the power grid.

- Non-financial Benefits: Work processing efficiency. Improved safety and reliability.
- Summary of Financial Benefits (if applicable) and Costs: N/A
- Technical Evaluation/Analysis: N/A
- Project Relationships (if applicable): N/A
- Basis for Estimate: Project scope, schedule, and vendor proposals.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	44	86	50	130		100
M&S	-	-	-	-		-
A/P	29	242	238	170		110
Other	-	-	-	-		-
Overheads	32	78	35	74		74
Total	**105**	**406**	**323**	**374**		**284**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	30	30	30	30	30
M&S	-	-	-	-	-
A/P	242	342	352	352	352
Other	-	-	-	-	-
Overheads	17	18	18	18	18
Total	**289**	**390**	**400**	**400**	**400**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Distribution Operations Training Simulator
Project Manager	Maggie Chow
Project Number	PR.21546535
Status of Project	In Progress
Estimated Start Date	2018
Estimated Completion Date	2023
Work Plan Category	Strategic

Work Description:

Distribution Simulator

Traditionally learning has relied on the job, academic classroom setting, understanding procedures and knowledge of equipment process. To be truly effective, there needs to be a learning and assessment tool that essentially conditions control center operators in how to respond to operational responses when dealing with complex systems. Such conditioning is accomplished through the use of dynamic simulation that utilizes hands on experience in a test environment that utilizes realistic experience based scenarios.

The objective is to allow Distribution Control Center Operators to learn and practice in a safe, non-threatening and controlled environment. The testing simulator needs to be continuously expanded to include lessons learned, process and procedure changes as well as new technology. The virtual environment will reconcile information from various sources including Reactance to Fault, substation relays, Feeder Management System Fault Correlation, reports of manhole fires, and Contingency Analysis. These are essential elements in the fault locating process. The simulator results will be used to analyze an operator's performance, and for qualification and requalification of new and experienced users.

Justification Summary:

System Simulation significantly enhances operator understanding of system complexity. In essence, it provides a powerful addition augmenting the integrated use of new and existing tools in processing events occurring on the system. This increases efficiency through the development of greater expertise. This application, through the development of scoring criteria, provides an objective mechanism that can determine skill levels before operators can be considered qualified. With the increasing retirement and the increasing complexity of our distribution design, it is critical that we have a new technological tool to stimulate learning and assess readiness for our operators. Similarly, when operators have exhibited deficiencies in their daily operation, they will need remediation. Training in a simulation environment is more effective and allows requalification to be met if a scoring criteria is satisfied. The net result is a better trained operator whose propensity for error is reduced and the speed is increased in system event processing. This is particularly important during multiple contingencies occurring in the summer.

<u>Supplemental Information</u>:

- <u>Alternatives</u>: There is no real alternative that provides the equivalent conditioning of operators and an objective qualification process based on dynamic operator response.

- <u>Risk of No Action</u>:
The continuing advances in technology SCADA and system complexity leads to a complexity of the tools utilized by operators. Maintaining operator expertise becomes increasingly challenging. This threatens the ability to operate expeditiously and error free and is not consistent with our Human Performance Improvement (HPI) Program. As our operations environment becomes more complex the risk of operating errors and their consequences of equipment damage, and injury to employees and the public increase.

- <u>Non-financial Benefits:</u>
The Company has developed and implemented a display for operating personnel that provides an integrated view of network and/or load area system conditions. The application allows the operators to navigate between the various applications as though they are all part of a single tailored application. The application facilitates the processing of primary distribution feeders from outage to restoration and analyzes the network or load area contingency for the "now" case and the "next worst" cases.

- The importance of having a complete and integrated knowledge of system conditions during contingencies is essential to successfully bringing the system back to normal status in a timely manner. The current process involves pulling out a feeder map, manually identifying the ATS' High Tension (HT), using an Excel spreadsheet to determine the next operation. Targeting the auto loop and 4KV primary grid will complete the loop by providing operators with the ability to quickly analyze system contingencies and assess next worse scenarios to respond more efficiently. Operators will also have a more accurate representation of the customer outages related to the system contingency and the next worse event.

- The Distribution Simulator is designed to support this initiative as well as other technological applications ensuring that these systems are expeditiously utilized in the daily operation.

- **<u>Summary of Financial Benefits (if applicable) and Costs</u>:**
Financial benefits are based on the avoided cost associated with operating errors which can be substantial.
- <u>Technical Evaluation/Analysis:</u>
Complete enhancements, new features and to improve the user experience of the existing Distribution Simulator including designing and developing content in an interactive, self-paced course for each scenario, add gaming elements (video game feel) to keep users interest, incorporate multiple choice questions and interactive feeder maps and create additional scenarios including MTA coordination during contingency planning. Some of the project benefits include: a safe, contained learning environment where the inevitable mistakes of a learner can be made without serious side-effects consistency of learning across personnel, since all operators will be exposed to the same set of experiences exposure to a wide range of situations, not limited to the situations that happen to arise during any particular shift comprehensive and retrievable documentation of operator performance.

- Project Relationships (if applicable):
  None

- Basis for Estimate:
  The cost to purchase and install distribution system control room readiness simulation software is estimated to be at $1.15M. The cost to purchase and install computer servers and laptops for the above distribution system control room readiness simulation software is $50k.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		300
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	**-**	**-**	**-**	**-**		**300**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	-	-	-	-	-
A/P	220	182	136	136	136
Other	77	50	12	12	12
Overheads	4	18	2	2	2
Total	**300**	**250**	**149**	**150**	**150**

X	Capital
	O&M

2019 Capital - Central Operations/System & Transmission Operation

Project/Program Title	Distribution Order Enhancements
Project Manager	Richard Scholz
Hyperion Project Number	PR.22249001
Status of Project	Ongoing Program
Estimated Start Date	January 1998
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

This project will implement enhancements to the applications running on the Operations Management Systems (OMS) that are used by the District Operators for issuing operating work orders. These enhancements are a collection of new capabilities which include, but are not limited to the following:

- Improvements to the programming for electronic issuance of operating orders
- Creation of new interfaces to corporate data and systems that interface with the existing programming
- Enhanced disaster recoverability
- Increased automation of field operations
- Upgrades to the diagrams that help the operator visualize connectivity of the distribution feeders within the network
- Appropriate upgrades and modifications will be developed and implemented during real-time use that further support reduction in feeder processing times, improvements to productivity, or aid in the prevention of operating errors

Justification Summary:

The operators currently rely on the OMS to aid in processing work and making operating decisions. The complexity of the transmission and distribution systems and their overlapping relationships rely heavily on informed operators equipped with state of the art tools. The interconnection of generation and the nature of interconnected operations continue to create challenges that require fast and well-informed responses to system conditions.

In order to further reduce feeder-processing time, additional areas in distribution order processing need to be automated and enhanced in order to keep up with changing technology requirements and to support the increased needs for efficiency.

Supplemental Information:

- Alternatives: The only alternative would be to maintain the system as is, however this poses a risk.

- Risk of No Action: The current system could be maintained without needed upgrades or support, however this would significantly reduce system reliability and the ability to update the system to reflect electric system upgrades/changes. There would be decreased automation and limited functionality in the future.

- Non-financial Benefits: Work processing efficiency and improved safety and reliability.
- Summary of Financial Benefits (if applicable) and Costs: N/A
- Technical Evaluation/Analysis: N/A
- Project Relationships (if applicable):N/A
- Basis for Estimate: Project scope, schedule, and vendor proposals.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	36	66	62	46		80
M&S	-	-	-	-		-
A/P	185	144	167	288		119
Other	-	-	-	-		-
Overheads	32	59	42	31		60
Total	**253**	**269**	**271**	**365**		**259**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	90	90	90	90	90
M&S	-	-	-	-	-
A/P	229	146	153	153	153
Other	20	13	13	13	13
Overheads	46	44	44	44	44
Total	**385**	**293**	**300**	**300**	**300**

X	Capital
X	O&M

2020 – Electric Operations

Project/Program Title	Electric Distribution SCADA Enhancement
Project Manager	David Pearce
Hyperion Project Number	PR.23317068
Status of Project	Initiation
Estimated Start Date	1/1//2020
Estimated Completion Date	2022
Work Plan Category	Strategic

Work Description:
Con Edison utilizes General Electric's XA21 (PowerOn) SCADA application to operate is SCADA enabled devices. This project will upgrade to the latest version of the software and upgrade the associated hardware. The upgrade is necessary to increase the capacity of the SCADA IT systems to be able to accommodate devices being added as a part of grid modernization and storm hardening, such as fully controllable network protectors and manhole sensors. The new version of the software is expected to have enhanced functionality and will be Con Edison's initial foray into Advanced Data Management Systems.

This request also covers funding for O&M expenses associated with staffing a Watch Engineer position in the Distribution Electric Control Centers ("DECC"). This position is a component of the defense-in-depth cybersecurity strategy in the DCCCs. Con Edison's DECCs are separated from the corporate wide area network by a set of firewalls, creating a High Value Network (HVN). The Watch Engineer will be responsible for approving and monitoring access to the HVNs, monitoring performance dashboards and intrusion detection tools that are being deployed under the DECC Cybersecurity program e.g. (SPLUNK, SolarWinds), providing 24x7 SCADA application support and server monitoring. The request increases staffing levels by 7 full-time employees.

Justification Summary:
The SCADA systems that support electric operations are a key component of several strategic initiatives. Without an upgrade the current SCADA application database will not be able to accommodate additional devices beyond 2020. Grid Modernization calls for the installation of thousands of new devices annually, and this would not be achievable with the existing SCADA database. Additionally the hardware is approaching the end of its vendor supported lifetime.

Con Edison personnel in IT, Distribution Engineering SCADA and Distribution Engineering System Design access the HVN networks to perform their daily work functions maintaining the SCADA system and critical applications used by the control centers and Regional Engineering. Access is currently provided by a remote virtual connection through jump host servers. Physically relocating all persons who require access within the physical confines of the HVN networks is prohibitively expensive and would necessitate the expansion of the HVN boundaries to the SCADA labs in Astoria, to a portion of the Van Nest shop, and to open plan office spaces that currently have no provisions for secure swipe access. Additionally, to obtain maximum value from monitoring assets being deployed, 24x7 monitoring is a best practice. Updating the XA21 system and adding a Watch Engineer will allow IT to provide our internal and external stakeholders know they need to operate effectively.

Supplemental Information:

- Alternatives:
  Continue to operate the current version of the XA21 application under an extended support agreement from the vendor, and delay any plans for adding significant numbers of SCADA enabled devices.

  Continue to allow remote terminal access without active monitoring. It has been proposed that Regional Electric Control Center (RECC) Shift Mangers can act as HVN gatekeepers to authorize logons. This presents an additional burden to RECC shift managers who are not familiar with the nature of work to be performed.

- Risk of No Action:
  We project that within the next 12-18 months the XA21 database will be at capacity. Beyond that point, new SCADA enabled devices will not be able to be connected to the system. Additionally there will be expiration of support for the older software version. Aging hardware would be prone to failure and it will be difficult to source parts.

- Non-financial Benefits:
  This project will allow for improved availability and reliability of DECC SCADA systems.

- Summary of Financial Benefits (if applicable) and Costs:
  The cost estimates of a cyber-breach to DECC SCADA systems can vary greatly based on the impact. A cyber breach of the DECC HVN can negatively impact public safety by disrupting the critical electric systems that serve the financial capital of the world.

- Technical Evaluation/Analysis:
  The XA21 application is the platform currently used by Con Edison electric distribution.

- Project Relationships (if applicable): Distribution automation, Storm Hardening and Smart Grid programs including utility of the future initiatives such as Reforming the Energy Vision (REV), and the introduction of distributed generation will increase the number of devices connected to our SCADA system.

- Basis for Estimate: The estimate is based on the cost of previous XA21 implementations (subject to inflation), and includes funding in the second and third year for field crews to perform certification of field devices. The funding for a watch engineer is based on 7 FTE positions, 6 Watch Engineers and one supervisor.

Annual Funding Levels ($000):

Capital

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	500	900	300	-
M&S	-	421	800	500	-
A/P	-	-	-	-	-
Other	-	37	71	45	-
Overheads	-	241	429	145	-
Total	**-**	**1,200**	**2,200**	**1,000**	**-**

O&M

Engineering and Other Services

Incremental Change due to this project to the Engineering and Other Services program
Future Elements of Expense

EOE	Request 2020	Request 2021	Request 2022
Labor	900	-	-
M&S	-	-	-
A/P	-	-	-
Other	100	-	-
Overheads	-	-	-
Total	**1,000**	**-**	**-**

Historical Elements of Expense total Engineering and Other Services program

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Actual 2018
Labor	6,139	6,328	6,468	6,347	5,851	5,417
M&S	191	213	147	76	36	32
A/P	987	1,525	603	1,929	882	319
Other	17,427	18,779	18,918	20,469	21,512	21,911
Total	**24,744**	**26,845**	**26,136**	**28,821**	**28,281**	**27,679**

Future Elements of Expense total Engineering and Other Services program

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	5,531	6,811	6,811	6,811	6,811
M&S	33	33	33	33	33
A/P	326	3,646	3,846	4,326	4,326
Other	22,372	22,372	22,372	22,372	22,372
Total	**28,261**	**32,861**	**33,061**	**33,541**	**33,541**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Electronic Feeder Sign On
Project Manager	Maggie Chow
Hyperion Project Number	PR.1XC1300
Status of Project	Programming
Estimated Start Date	In Progress
Estimated Completion Date	2023
Work Plan Category	Strategic IT Enhancement

Work Description:
On June 27, 2004, the Company reached an agreement with the Union to expand the range of positions and job categories authorized to sign on to electrical work. This included the set of workers known as "Distribution Splicers". Previously, supervisors had been responsible for signing crews on to all splice work. Adding this responsibility to the distribution splicers was intended to make sign-on more efficient by eliminating the need for supervisors to be at each job location in order for sign-on to occur. Sign-on was no longer limited by the number of supervisors available and crews no longer had to wait for a supervisor to arrive to begin working. However, significant challenges existed. With more people signing on concurrently, this creates a greater load on the sign on process at the control center. Also, adding new distribution splicers requires training and experience.

A new Electronic Feeder Sign On (FSO) system has been developed using the business case, scope and detailed user requirements developed by Edison Project with all operating regions in 2007 to interface Rapid Restore and Mobile dispatch to allow qualified employees to sign on to feeders effectively and safely, this will reduce the phone call traffic to the Control Centers and accelerate the current "call in" sign on process. Three Sign On modules will be incorporated into this application: Crews signing on to perform spearing/clantech & cutting, pulling, and splicing of cable.

The FSO application interfaces with Rapid Restore. Rapid Restore is an application that allows you to get real-time views of feeder repair. Authorized personnel can access Operating Orders and Work Permits as well as communicate with Substation Operations, Field Operating Department and the Energy Control Center.

Some of the most recent completed work by our internal IT department includes:

- The next version of the Rapid Restore Feeder Control Representative instructions module easier to maintain going forward.
- Working on several enhancements (Directional Tags, Label changes, business validations) to provide better user experience.
- Matching the cable type between two structures on the same permit on a feeder that has multiple structures (locations), the cable type should be the same and match between the two structures for cable scope. This enhancement is needed for accurate data and blocking the user when there is incorrect information entered.

- Error messages handling - Making the error message more visible and highlighting the error component in notification window where the mismatch/discrepancies exists to help FCR.

The planned work to be developed between 2018-2022 is the following:

1. Develop scope of work change module to allow for edits in the spear/cut, cable and splice modules. Allow the Feeder Control Representative (FCR) to update the current location details if a crew wants to issue a verbal scope of work change after electronically signing on.

2. Develop improved tag validation through the FCR, when the FCR instructions are created.

3. Expand FSO to include I&A (Instruments and Apparatus) group transformer work.

4. Attach the layout for a job to the location in the Crew Management module in FSO.

5. Allow FCR to see the feeder sign-on screens while the field is signing on.

6. Integrate Electronic Sign On with GPS technology that will compare the GPS location of the worker via MDT (Mobile Data Terminal)/Tablet/Rocket to the location of assigned structure where the worker is given the permission to sign on; this will further extend another layer of safety validation.

7. Further integration with other Company application such as Work Management System (WMS) for work assignment and System Operations Feeder Management System (FMS) enhancements

New ideas are continuing to arise and we will continue to work with the end users for continuous improvement to this safety and productivity enhancement project. Within the budget approved for 2018 through 2022, we will continue to work on the high priority items listed in the whitepaper and address the unforeseen items as the project continues to expand.

Justification Summary:
These improvements will reduce the phone call traffic to the control centers and accelerate the current "call in" to the sign-on and sign-off process. Additionally, the electronic sign-on process will enforce standardization and additional checks and balances for feeder sign-on/off. Implementing an electronic feeder sign on will allow the Company to apply technology to alert workers when work on feeders is available for them to begin and enhance safety by using the notification module in the application. The notification module alerts both the FCR and the Splicer when there are discrepancies and/or to other important FSO events during the electronic sign on process. We also reviewed the last 5 years of operating errors to identify if Electronic Feeder Sign-on was available during those years. By implementing this new technology, we could have avoided 10% of the errors. See below supporting chart to show how many operating errors were found in a 5-year period and the 10% of errors (19) that could have been prevented utilizing FSO and its notification alerts.

Adding the responsibility to sign-on to the distribution splicers was intended to make sign-on more efficient by eliminating the need for supervisors to be at each job location in order for sign-on to occur. The sign-on process was no longer limited by the number of supervisors available to sign crews on feeder work and the efficiency losses this created. After this improvement to the process, crews were no longer delayed by waiting for a supervisor to arrive before signing-on and off, but still experience a delay waiting for the control center feeder representative to become available for the verbal sign-on/off orders. Electronic feeder sign-on is intended to address this delay and eliminate this bottleneck. Without it, the full benefits of achieving this responsibility change and allowing crews to sign themselves on feeder work will not be fully realized.

Supplemental Information:

- Alternatives: None

- Risk of No Action:
  System will remain utilizing the current manual sign-on process relying on operating orders to be exchanged via phone voice calls and direct operator interaction. However, there still remains a bottleneck of a high volume of calls in to the control center that limits efficiency of the process.

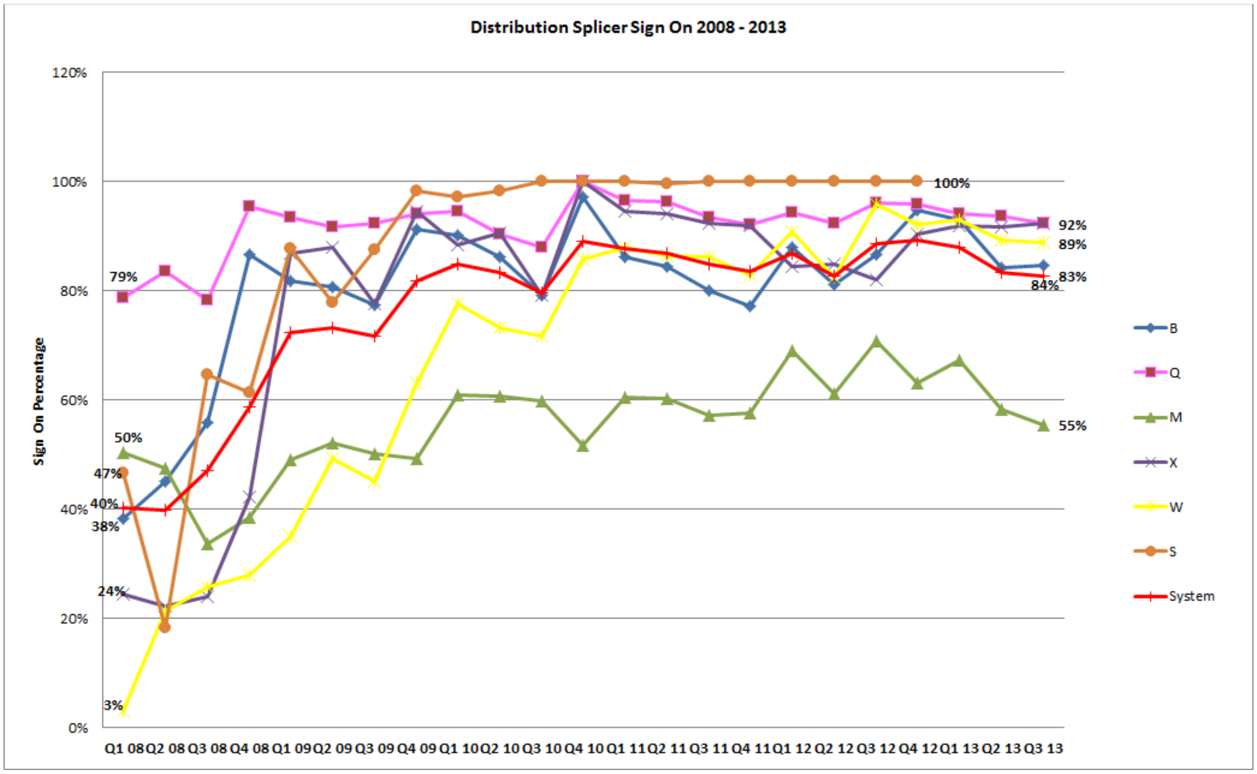
  Currently, the process by which Con Edison workers sign on to perform feeder repair work is manually-driven, involving direct two-way verbal communication with the control center in all cases. Each control center has one regional FCR on a shift to sign workers on manually. Delays occur as crews wait their turn to sign on with the single FCR and this delay could be quite significant. Delays are exacerbated by the interdependent nature of the work itself – downstream delays result when work is not completed on time, on shift, or in time for other work to begin on schedule. As indicated in Figure A, the Edison Project team led the efforts with the Regional Management to steadily increase the distribution splicers sign on rate from 23% (in 2007) to 84% in 2013. This effort highlights the need for an automatic electronic feeder sign on application. Schedule gains (time for completion), schedule improvement (ability to meet expectations) and resource utilization could all be improved if the sign on process could be made more efficient.

- Non – financial Benefits:
  The electronic feeder sign-on process will create and enforce consistency across the organization in how workers are authorized to sign on, how they are trained, and the sign-on procedure itself. This will in turn increase the safety and transparency of the sign-on process. Operators should also see a decrease of incoming calls from Cable Splicers and Splicers coming into the Control Centers.

- Summary of Financial Benefits (if applicable) and costs:
  One of our main goals has been to reduce the feeder processing times; by reducing the time the feeder is kept out of service, the occurrence of cascading feeder outages is also reduced. The bottleneck that occurs during sign-on also occurs during sign-off, after the crew is done with their work. The electronic sign-on application will allow crews to sign off within a few minutes of completing their jobs. Increased crew productivity is also one of our main targets. By reducing the waiting time for sign-on and sign-off events, it will increase the availability of crews to perform productive work before the end of their shift, and allow the FCR to focus on the more complicated sign-on tasks that require additional human interactions.

  The feeder sign-on application will eliminate a good proportion of this delay by automatically alerting the FCR that sign-off is complete so they can review the completed work and return the feeder back to the jurisdiction of the District Operator (DO) who will process and return the feeder to service.

- Technical Evaluation/Analysis:



This figure shows the increase in the distribution splicer sign on rate from 23 % in 2007 to 84% in 2013. The chart reflects the steady increase in this activity which has led to the bottleneck with a larger number of instances where crews now need to sign-on to feeder work and are participating in a sign-on process dependent on the issuance of verbal orders.

- Project Relationships (if applicable):
  N/A

- Basis for Estimate:
  Estimates received to add functionality by Phase of Project.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	86	94	-	-		16
M&S	-	-	-	54		-
A/P	554	284	16	205		377
Other	-	0	18	3		-
Overheads	59	75	1	113		8
Total	**699**	**453**	**35**	**375**		**401**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	62	60	60	60	60
M&S	-	-	-	-	-
A/P	237	238	238	238	238
Other	21	21	21	21	21
Overheads	33	31	31	31	31
Total	**353**	**350**	**350**	**350**	**350**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Emerging IT Project Initiative for Enhanced Distribution System Analysis
Project Manager	Troy Devries
Hyperion Project Number	PR.NXC0001
Status of Project	In Progress
Estimated Start Date	Ongoing
Estimated Completion Date	2019
Work Plan Category	Operationally Required

Work Description:
The Emerging IT Project Initiative for Enhanced Distribution System Analysis provides funding for the development of new Information Technology (IT) projects or enhancements that increase system monitoring functionality, improve operator performance, improve outage management (OMS) performance and visibility, provide field crews greater mobility functionality and capability or enhance the customer experience.

Examples of projects worked under the Emerging IT Project Initiative for Enhanced Distribution System Analysis includes the following:

Distribution Engineering Dashboards – This project is for development of various dashboards residing on a single distribution homepage that provides engineers, particularly those functioning in an operations support role, access to data from a multitude of sources. The Engineering Dashboards will allow engineers and operators to support operations by conducting advanced analysis through seamless access to data from databases including: asset repository, reliability performance, load flow, equipment availability, inspection, maintenance and others.

Transformer Failure Risk Analysis – Con Edison is in the process of deploying remote monitoring system pressure temperature and oil level sensors across its fleet of distribution transformers. Underground distribution transformers have been equipped with pressure, temperature and oil sensors. This sensor is producing significant amounts of data that provides a benefit of reducing risk of transformer failure but requires significant effort to analyze. The Company has developed several algorithms that identify transformers with pressures, temperatures or oil levels outside of acceptable ranges and notifies the equipment engineering team. These algorithms and an engineering team review have resulted in 645 defective transformers being removed from the system since 2008, reducing risk to the public. The continuation of work on this project will advance the algorithm capability to improve its accuracy as well as reduce the resources and time required to review transformer sensor data thus improving process efficiency and providing quicker field response to transformers at risk of failure.

Second Fault Detection System – Con Edison has identified the detection of negative sequence current during feeder faults as an indicator that there may be a second fault on a distribution feeder. Early awareness of the presence of a second fault on a distribution feeder is extremely useful from an operational perspective as it allows operators to take actions that best reduce feeder restoration time. This effort will integrate negative sequence data into the Power Quality (PQ) view system and ultimately the Heads Up Display (HUD) system to optimize feeder restoration time.

We have developed a first generation algorithm that detects the presence of a second fault on distribution feeders. We initially applied this algorithm in Brooklyn and Queens since these areas have the greatest number of feeders failing on test (FOT) after repair, often an indication of a second fault. Preliminary tests of this algorithm show an overall 82% success rate in predicting second faults or, more importantly, confirming no second faults. Given this early success, the project expanded implementation of the first generation algorithm into the Company's other operating areas.

Continuing work on the project is needed to improve the accuracy of the algorithm. In 2017, the replacement of power quality monitors installed in substations began. The newer units have higher sampling rate and also more advanced triggering options compared to the old monitors. In addition to better capabilities, the new units are still serviceable, while the older ones lack easily found replacement parts. Finally, upon installation of the new monitors, many times we are able to double wrap the flexible Current Transformers (CTs) used to monitor current, resulting in even more detailed measurements. This should all lead to more accurate 2nd fault monitoring.

Outage Management System Enhancements - The use of CECONY's Outage Management Systems (OMS) and associated dashboards is critical to operators and other mid-high level managers to ensure the efficient assessment and response to incidents impacting service to our customers. Continued enhancements and integration of OMS with other technology is critical to ensuring continued focus on our customer needs. The Company continues to make significant improvements in its ability to quickly understand the number of customers impacted by power disturbances and provide customers with timely estimated time of restoration (ETR). These accomplishments were achieved through a series of process improvements and enhancements of the Outage Management suite of systems including STAR (System Trouble Analysis and Reporting). STAR is based on Oracle's OMS software suite. Increased attention to providing timely ETRs as well as enhancing the accuracy of customer impacts via the integration of supervisory control and data acquisition and advanced metering infrastructure (SCADA and AMI) underlines the need to continue focus on outage management systems.

BI/Outage Management Dashboard Upgrade - This project is an upgrade to our existing Outage Management Dashboard Business Intelligence (BI) which today provides various outage-related information and reports utilized by internal departments, such as Electric Operations, Emergency Management, Public Affairs and Customer Operations. The upgrade will provide greater visibility both within and outside the Company into the various outage related processes such as Customer Outages, Damage Assessment, Restoration Planning, Manhole Events and ETR management. In addition, to the software upgrade, an upgrade to the related computer hardware will be required as the current equipment will be reaching the end of its useful life.

Work Management System - The Work Management Project including process change, organization restructuring and the deployment of CGI-Logica ARM Suite (Work Manager, Scheduler, Central Configuration, Asset Manager and Mobile Field Manager) completed project implementation at the end of the 4th quarter 2014.

In 2015 the Work Management Governance team concluded a Gap Analysis review. The Governance team focused on several findings. These findings included enhancing Management Engagement through various checklists and process implementations, Compatible Unit (CU) Simplification to develop and group CUs into larger Master Unit sets, process refinement for Time Reporting and Approval functions, Technology review and refinements for Mobile and core applications. In addition the development of the Model Office Initiative was deployed throughout the various regions to implement best practices and process compliance.

The team initiated quarterly deployments of CGI-Logica release to address known defects and enhancements to the application.

The Capital requirements will address server hardware upgrades including SAN units and associated Oracle software licenses.

Developer support (internal and external) will enhance process or applications as new Electric Operations construction and operating requirements are developed and requested by various stakeholders. This includes approximately 25-35 CGI-Logica requests to change the core application, hardware costs to address server hardware and licensing, new requirements for Customer Excellence initiatives, and asset manager analytics for facility optimization.

Governance and Sustainability part of the project will continue as an on-going part of the Work Management solution. Governance will include addressing application defects as found during utilization of the core CGI-Logica ARM Suite of applications, as well as defects found during utilization of interfaces to various other application systems such as Oracle Project Accounting, Oracle Labor Distribution, the Customer Project Management System (CPMS) application, HR Payroll PeopleSoft, LayOut Tracking (LOTs) system and PowerPlant and other applications that use the BizTalk and/or other customer-built interfaces.

Customer Project Management System (CPMS) Enhancements– CPMS was installed in 2013 with the purpose of enhancing the customer experience by streamlining and refining processes after a request for new or upgraded electric service is submitted by a customer. The second major enhancement to CPMS included enhancing customer-facing interactions including self-service scheduling of inspection appointments, new mobile functionality for customers to accomplish a number of case-related tasks using a cell phone, a new customer inquiry feature to manage and track customer questions, and new analytic tools. Future plans include the development of Customer Knowledge Self Service (CKSS) project plans to add the following functional capabilities:

1) Omni Channel Communications
2) Index Management Crawler (IMC)
3) Chat Bot
4) Machine Learning/Artificial Intelligence

This functionality will further assist our customers with the information they need to make more informed decisions regarding their electric and gas service.

<u>Justification Summary</u>:
The significant amount of data available across the systems of the company presents an unprecedented opportunity to mine information for useful relationships and create engineering and operational value for

minimal cost by combining information from different systems and applying analytics to the resulting dataset.

New technology can be leveraged to improved system analytics, present operators with current system conditions, device loadings and recommend system reconfigurations or actions as needed and improve our customer experience by presenting them with data and information needed to make decisions to meet their electric and gas usage.

Supplemental Information:

- Alternatives: The alternative to this project is to develop individual dedicated information systems for each of the applications identified. This would be more costly than the proposed method of combining data from various systems to provide incremental value to our engineering and operations.

- Risk of No Action: New technology presents an opportunity to further improve engineering and operational performance. Failure to take advantage and enhance the systems described will deny engineers and operators:
    - Critical operational information that will result in less effective performance with delayed restoration times
    - The ability to anticipate impending faults and proactively remove feeders to protect the system.
    - The ability to model analyze and predict potential distribution transformer failure
    - The ability to identify the potential for second faults on distribution feeders resulting in delayed restoration time and greater risk to the network
    - The ability to identify the source of bus faults and delay restoration
    - The ability to more quickly identify and respond to feeder faults resulting in delayed restoration times and greater risk to the network.
    - The ability to accurately model non-network risk and identify optimal design, maintenance and operational strategies to reduce network risk

      .

- Non-financial Benefits: Advanced Engineering and Operational support tools will provide improvements in employee and public safety, reliability and reductions in cost.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: See work description

- Project Relationships (if applicable): None

- Basis for Estimate: The basis for the estimates are specific to each of the particular sub-projects for the overall project.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	94	100	-		-
M&S	-	-	-	-		-
A/P	-	284	338	-		272
Other	-	-	-	-		24
Overheads	-	75	60	-		4
Total	**-**	**453**	**498**	**-**		**300**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	91	192	1,117	719	2,840
M&S	-	486	4,865	4,000	3,204
A/P	785	2,726	3,877	4,119	3,795
Other	70	285	776	721	622
Overheads	54	133	637	442	1,401
Total	**1,000**	**3,823**	**11,272**	**10,000**	**11,861**

X	Capital
	O&M

2019 Central Operations/System & Transmission Operations

Project/Program Title	EMS Replacement AECC and ECC
Project Manager	Michael Threet
Hyperion Project Number	PR.20476558
Status of Project	Planning
Estimated Start Date	January 2019
Estimated Completion Date	December 2020
Work Plan Category	Strategic

Work Description:

This project will replace the existing Energy Management System (EMS) that monitors and controls both the electric transmission and distribution systems. This system provides the users with an EMS that provides reliable system operability using the latest technologies and user interfaces. The dual redundant primary and standby systems are designed for complete independent operation from either control center. This project is planned to start in 2019 and be completed in 2020

Justification Summary:

Periodic replacement/upgrade of the EMS is necessary to ensure that the computer systems can continue to be supported and to take advantage of the latest operator tools being provider by EMS vendors. This is needed to ensure that the system will provide improved features for operators and support staff and meet the ever evolving cybersecurity challenges and emergent compliance requirements such as the North American Electric Reliability Council (NERC) Critical Information Protection (CIP) standards.

Vendor software releases occur approximately every 18 months, and computer hardware life of the product is about 5 years. Most of the current system was purchased in 2012 and its end of life has been declared by the vendor to be on 9/30/2015; that's when the product is no longer in production making it harder to find parts and replacements (it becomes obsolete in a few years after that). Also, the replacement of the hardware is necessary to maintain the capability of meeting performance requirements and to avoid losing hardware and software support provided by our vendors.

Supplemental Information:

- Alternatives:

  Leave the system software and hardware at their current levels and do not take advantage of enhancements or system upgrades. This option risks the loss of security patch support, placing the system without antivirus / malware protection. It also could result in the loss of vendor support for the baseline software fixes and enhancements. Not providing the ability to enhance the EMS would cause the system to eventually become less effective in meeting our operational goals and would not provide the benefit of using the latest features.

  By not maintaining operating systems and system hardware at near industry standards, the EMS systems and software would no longer be supported by the vendor and its 3rd party suppliers. The loss of vendor support for security patch releases would make the EMS non-compliant with NERC CIP regulations, resulting in potential financial penalties for non-compliance.

- Risk of No Action:

  Not enhancing the EMS would cause the system to eventually become less effective in meeting our operational goals. In addition, by not maintaining operating systems and system hardware at industry standards, the EMS systems and software would no longer be supported by the vendor and its 3rd party suppliers by end of 2020 (approximately 5 years after the declared end of life of 9/30/2015). The loss of vendor support for security patch releases would make the EMS non-compliant with NERC CIP reliability standards, resulting in the potential for the Company to incur financial penalties for non-compliance.
- Non-financial Benefits:

  The EMS replacement will take advantage of the latest vendor functionalities and make the system more secure. This will be achieved by keeping current when it comes to bug fixes and security patches are released, an important criteria for meeting NERC CIP requirements. The new hardware will also provide added computational power and increased memory speed, which are essential in the ever increasing demand for processing power required by new tools and feature.
- Summary of Financial Benefits (if applicable) and Costs:

  N/A
- Technical Evaluation/Analysis:

  N/A
- Project Relationships (if applicable):

  EMS Reliability AECC and ECC. Note that the EMS Replacement was carried out as part of the EMS Reliability AECC and ECC but it has been made a separate project under this filing.
- Basis for Estimate:

  Actual costs of the last EMS Replacement project, adjusted for escalation costs.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	250	250			
M&S	0	0			
A/P	2,982	3,916			
Other	265	348			
Overheads	159	170			
Total	**3,656**	**4,684**	-	-	-

X	Capital
	O&M

2019 – Construction

Project Program Title	Field Smart Forms
Project Manager	John Minucci / Joe King / Stephen Conklin
Project Number	PR.21751618
Status of Project	In Flight
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
The Public Improvement organization will add new functionality to the capturing of field data in Construction's Public Improvement Interference work on New York City Public Works Projects. This system will maintain one document repository for all city work as received from the Department of Design and Construction (DDC) and Public Works. The documents will include the project description, layouts, blast notifications, and notice to proceeds, invoices and authorization approvals. This will include a mobile solution for data collection of actual field activity and conditions. The forms will include the Daily Activity Report (DAR) / Field Activity Report (FAR). We will be using the KONY mobile architecture which will work on smart phones, tablets, laptops and desktop computers. This will include new electronic forms and the ability to capture video and photographs of contractor work. This will enable field forces to capture documentation of field activity. The next phase of the project which includes newly developed digital field forms will deployed in 2018.

Justification Summary:
This project is important in our continued quest for project control, transparency and reporting as it relates to city projects. We will be able to see the progression and completion of these multiyear Public Works projects. Our current method for capturing the field activity of the contractors is manual. This adds some additional time in review field activities for status and payment. The new digital forms will give us digital audit trails of activities.

Supplemental Information:

- Alternatives: Keep the current reporting method of manual field documentation. This includes manual drawings and manual preprinted forms. The new system will provide digital audit trails, enhance processing of activities

- Risk of No Action: Less Transparency to negotiate better pricing for the items of work used in Interference portion of the Public Works projects.

- Non-financial Benefits: This will enable better response to audits, supplier invoicing questions, and project budget
- Summary of Financial Benefits (if applicable) and Costs:
  The implementation of this module will provide the following benefits:
  Reduced clerical resources.
  Reduced overtime related to this activity.

Reduced costs in processing of payments.

- Technical Evaluation/Analysis: The new technology being used for the mobile technology is cloud based and will enable us to collect data in disconnected mode. The electronic forms will work on all of our hardware platforms. The architecture was reviewed and approved by information resources as a viable solution for this effort.

- Project Relationships (if applicable): Oracle EBS / Work Management System (WMS
  The information being captured will be used in our technical review process for the validation of contractor payment information. Once the validation is completed the information will be sent electronically to Oracle EBS for processing.

  The Work Management System (Logica) will have specific tasks and activity which will be available for updating via the smart field forms. This will enable increased transparency to documentation, field activities and visualizations.

Total Funding Level ($000):

Historical Elements of Expense

(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	**-**	**-**	**267**	**323**		**270**

Request by Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor					
M&S					
A/P					
Other					
Overheads					
Total	**225**	**250**	**250**	**250**	**250**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Integrate Machine Learning Models-CAP
Project Manager	Maggie Chow/ Chris Jones
Hyperion Project Number	PR.9XC9815
Status of Project	In Progress
Estimated Start Date	2014
Estimated Completion Date	2023
Work Plan Category	Strategic IT Enhancements

Work Description:
The Contingency Analysis Program (CAP) assists control center operators in making operating decisions during system contingencies. CAP consolidates data from multiple systems and implements decision algorithms which provide guidance to operators on next actions.

The broad goals of this initiative are to:

- Extract and combine vital information from a number of different systems including:
    - Distribution Information System (DIS)
    - Remote Monitoring System (RMS)
    - World-class Operations Load Flow (WOLF)
    - Distribution Overhead System (DOS)
    - Unit Substation Automation (USA)
    - Virtual Memory Data Acquisition Management System (VDAMS)
    - Feeder Management System (FMS)
    - General Electric's Extensible Architecture for the 21'st Century (XA21)
    - Customer Outage System
    - Emergency Operating System (EMOPSYS)
    - Load Aggregator

- Integrate data across separate applications and provide this critical information to operators in a way that they can interpret and act upon quickly. Decision aid tools help operators analyze data from a multitude of systems quickly enough to implement corrective actions.

- Provide this critical information to operators in a single, actionable view.

Here are some of the recently completed modules and future modules of CAP to be developed between 2019 and 2022 include:

Multi-year plan for Distribution Contingency Analysis

Module	Description	Target
Module 1	Enhance visualization to improve user's Situational Awareness (SA) design for NW system	Complete
Module 2	Enhance visualization to improve user's Situational Awareness (SA) design for Auto Loop and 4kv system	Complete
Module 3	Add banks off reason, 4kv feeder load graph, at risk ISO column	2018
Module 4	Make fields clickable for Feeders Out, Overloaded (O/L) Sections, O/L Transformers, PTO, Dropped HTV, Dropped ISO, At Risk Multibanks, and Unit Sub Out.	2018
Module 5	Establish interface to CDMS (XA21)	2019
Module 6	Provide additional interface with FMS	2019
Module 7	Develop conflict and analysis model with FMS interface	2019
Module 8	CAP Graphical display with cluster identification	2019
Module 9	Provide Auto-loop load flow contingency analysis	2019
Module 10	Provide 4kv load flow contingency analysis	2020
Module 11	Include Underground loop system in CAP	2020
Module 12	Establish SA summary page to include 4KV now and next worst contingency overloads	2020
Module 13	Correlate multibank contingency with secondary status for operator awareness	2020
Module 14	Provide Seamless capability to run test cases from the main display for "what if" scenarios in NNW (similar to Manual Cap for NW)	2021
Module 15	Calculate and display now and next worst contingency for secondary cable overloads	2021
Module 16	Provide interface with HTV Supervisory Control and Data Acquisition (SCADA)	2021
Module 17	Provide capability/logic to trigger to run contingency on any combination of equipment and feeders (other than from feeder OA)	2022

Module 18	Incorporate automatic status update of overhead utilizing OMS and overhead switching	2022
Module 19	Incorporate Area Substation Over load	2022
Module 20	Decision Aid Action Engine	2022

<u>Justification Summary</u>:
CAP was developed as a decision aid for control center operators to help them analyze system contingencies. System contingency analysis and response by operators in our control centers is a human-intensive process that can quickly overwhelm operators. CAP assists operators by presenting them with the most vital information on current system status and providing guidance on next actions. CAP works to address the following concerns:

- What is the current abnormal state of the distribution system?
- What is the current impact?
- What is the impact and severity of the next event?
- What are the best options for getting the system back to a normal state?

Historically, to address these concerns operators had to gather information that is contained in over 20 applications. This is a laborious process because each application typically requires a separate login with a user ID and password. While this provides a picture of the current status, the resulting view is not dynamic and needs to be manually constructed after an event.

<u>Supplemental Information</u>:

- <u>Alternatives</u>: The main practical alternative to consolidating data from multiple systems and providing decision tools to operators, as implemented by CAP, is to continue manually accessing multiple data sources to piece together vital information. Contingency analysis requires an integrated view of the condition of the distribution system which CAP provides. CAP's ability to push vital system information to operators in the form of current conditions and subsequent scenarios is a beneficial feature for control center operations.

- <u>Risk of No Action</u>: Operator efficiency will be impacted without the further enhancements offered through the CAP initiatives. Control operators will have to rely on the current disparate group of applications to collect relevant information. For example, to determine which customers are impacted in either high tension, multi-bank, or non-network systems, operators must combine SCADA information from numerous 4 kV auto loop systems by sorting through many pages of WOLF reports.

  Miss opportunity to improve the current process.

- <u>Non-financial Benefits:</u> The Company has developed and implemented a display for operating personnel that provides an integrated view of network and/or load area system conditions. The application allows the operators to navigate between the various applications as though they are all part of a single tailored application. The application facilitates the processing of primary distribution feeders from outage to restoration, and analyzes the network or load area contingency for the "now" case and the "next worst" cases.

The importance of having a complete and integrated knowledge of system conditions during contingencies is essential to successfully bringing the system back to normal status in a timely manner. The current process involves pulling out a feeder map, manually identifying the automatic transfer switches and high tension customers. Targeting the auto loop and 4KV primary grid will complete the loop by providing operators with the ability to quickly analyze system contingencies and assess next worse scenarios and allowing for faster response times. Operators will also have a more accurate representation of the customer outages related to the system contingency and the next worse event.

- Summary of Financial Benefits (if applicable) and Costs: The Company estimates that the implementation of CAP V will result in an average reduction of five minutes per outage and an annual savings of approximately $10 million to customers.

  A five minute reduction per outage corresponds to a 0.08 reduction in Customer Average Interruption Duration Index (CAIDI), equivalent to an average reduction of eight customer outage hours per 100 customers interrupted.

  Regarding customer cost savings, a study conducted by Berkley National Laboratory and sponsored by the US Department of Energy entitled *Framework and Review of Customer Outage Costs*, computes potential costs of power interruptions to U.S. electricity customers. The report estimates outage costs at $8,200 per hour for large commercial customers, $1,200 per hour for small commercial customers and $3.00 per hour for residential customers. Adjusted for inflation and locality, these costs are $13,722 per hour for large commercial customers, $2,008 per hour for small commercial customers and $5 per hour for residential customers.

  A reduction of five minutes per interruption due to CAP has the potential to save impacted electric customers approximately $10.6 million.

- Technical Evaluation/Analysis: CAP has been a success throughout the regional control centers and received recognition in the form of a team award. The initial phase of CAP has focused on the underground network systems in Manhattan, Brooklyn/Queens and the Bronx. The focus on the non-network system began with the overhead auto-loop system in Brooklyn/Queens, Bronx, and Westchester. In 2012-2013, CAP began to target the 4kV primary grid systems in Staten Island and Westchester. The work planned for CAP involves:

  - Integrating 4 kv SCADA from USA/XA21 to summarize the equipment status and the potential for loss of customers in a single view in CAP
  - Integrating 4 kv and Auto-Loop load flow contingency output to CAP – for the summary of next worst, overloaded equipment and pro-active preparation for customer outages
  - Redesigning CAP display with situational awareness screen to improve the human computer interaction and user centered design principles
  - Interfacing with FMS to provide seamless conflict and contingency analysis to improve safety and reliability.
  - Introducing a Decision Aid Action Engine to identify action for operators or field crews in response to system anomalies.

  Currently, operators rely on several sources of information (hardcopy maps, USA, High Tension, ECS, Outage Manager, Wolf, Rapid Restore, STAR etc.) for analyzing contingencies involving the 4 KV grids. There is no modeling tool integrated that allows contingency analysis in the non-network systems to be summarized. The problem is compounded in combination feeders which have overhead, network and 4KV components.

This latest module to CAP will bring this capability to the operators by automatically pulling information from these disparate data sources and feeding them to PVL which will quickly analyze the current and next worse scenarios and push this information to the operators through the CAP V in the non-network system.

- Project Relationships (if applicable): None

- Basis for Estimate: Actual costs of CAP implementations to date.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	1	-	-	8		142
M&S	-	-	-	-		-
A/P	77	21	-	33		40
Other	23	71	-	12		-
Overheads	1	-	-	4		69
Total	**102**	**92**	**-**	**57**		**251**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	229	227	227	227	227
M&S	-	-	-	-	-
A/P	20	20	20	20	20
Other	-	-	-	-	-
Overheads	3	3	3	3	3
Total	**252**	**251**	**250**	**250**	**250**

X	Capital
X	O&M

2020 – Electric Operations

Project/Program Title	Outage Management System IT System Hardening
Project Manager	David Pearce
Hyperion Project Number	PR.23317064
Status of Project	In Progress
Estimated Start Date	10/1/2018
Estimated Completion Date	12/31/2020
Work Plan Category	Strategic

Work Description:
In March of 2018, Con Edison's service territory was impacted by three Nor'easters in rapid succession. These weather events had an adverse impact on the level of service experienced by our customers. After these events an independent assessment of the Company's response was performed by McKinsey and Co. This assessment identified several areas for improvement in Information Technologies and Systems that can enhance the Company's performance in comparable weather events in the future. The existing systems were installed for a variety of largely standalone applications, such as Outage Management, control of electrical devices through Supervisory Control and Data Acquisition (SCADA) systems, and Outage Communication Dashboards. To meet our customer's expectations around the accuracy of ETRs (estimated time of restoration) several of these systems will have to be enhanced and their operations integrated.

In order to increase the effectiveness of the Outage Management System, the following enhancements will be undertaken.

- Replacement of the Obvient platform
- Upgrade the iFactor platform
- Implement changes to the electric distribution computer models to achieve improve outage prediction performance.
- Integrate SCADA data into Outage Management (OMS) systems.
- Re-Architect the Customer Communication Interface to ensure consistent messaging on the customer's platform of choice.
- Build an end to end testing environment to fully validate the operation of all IT systems for a system event.

Justification Summary:
As a result of these large scale weather events in 2018, the Outage Management System saw high volumes of outages which tested its ability to meet our customers' expectations. The system was originally designed and deployed to operate in a stand-alone configuration. To make use of data that currently resides in discrete applications, these systems will need to be upgraded or replaced. These upgrades will further enhance the performance of the Outage management Systems during future extreme weather events to meet customers, governmental and regulators expectations regarding timely and accurate information including ETR status.

Based upon findings and recommendations from "Winter Storms Riley and Quinn March 2018", this addresses functionality enhancements needed for this system.

Supplemental Information:

- Alternatives:
  The alternative option is to not make any enhancements to the current Outage Management System and operate the systems as they are today. This will lead to some smaller improvement in capabilities over time, but without a strategic plan to integrate the various sources of data and communication platforms the systems will lack the efficiency improvements that have been identified to meet customer's expectations.

  Risk of No Action:
  - Fail to take advantage of the identified enhancements to the Outage Management System.

- Non-Financial Benefits:
  These improvements will increase the ability to communicate outage information to customers. The project will improve customer satisfaction as well as our relationships with municipal agencies and our regulators.

- Summary of Financial Benefits and Costs:

- Technical Evaluation/Analysis:
  The technical evaluation is based on the findings of an individual consultant working in conjunction with subject matter exerts in several IT and business units.

- Project Relationships (if applicable):

- Basis for Estimate: Historic purchases are used as well as vendor presentations.

Annual Funding Levels ($000):

Capital

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	1,756	3,000	3,000	1,500	-
M&S	4,000	5,074	5,087	2,547	-
A/P	-	-	-	-	-
Other	355	451	452	226	-
Overheads	889	1,476	1,461	727	-
Total	**7,000**	**10,000**	**10,000**	**5,000**	**-**

O&M

Engineering and Other Services

Incremental Change due to this project to the Engineering and Other Services program
Future Elements of Expense

EOE	Request 2020	Request 2021	Request 2022
Labor	80	-	-
M&S	-	-	-
A/P	1,900	-	-
Other	20	-	-
Total	**2,000**	**-**	**-**

Historical Elements of Expense total Engineering and Other Services program

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Actual 2018
Labor	6,139	6,328	6,468	6,347	5,851	5,417
M&S	191	213	147	76	36	32
A/P	987	1,525	603	1,929	882	319
Other	17,427	18,779	18,918	20,469	21,512	21,911
Total	**24,744**	**26,845**	**26,136**	**28,821**	**28,281**	**27,679**

Future Elements of Expense total Engineering and Other Services program

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	5,531	6,811	6,811	6,811	6,811
M&S	33	33	33	33	33
A/P	326	3,646	3,846	4,326	4,326
Other	22,372	22,372	22,372	22,372	22,372
Total	**28,261**	**32,861**	**33,061**	**33,541**	**33,541**

X	Capital
	O&M

2019 Capital - Central Operations/System & Transmission Operation

Project/Program Title	Operation Management System Enhancements
Project Manager	Richard Scholz
Hyperion Project Number	PR.22249004
Status of Project	Ongoing
Estimated Start Date	NA
Estimated Completion Date	NA
Work Plan Category	Strategic

Work Description:
This project will address upgrades to the Operations Management Systems (OMS) computer systems and provide for expansion of these systems to better support the needs of the operators and field services. This work will also support infrastructure needed for replication of systems at the Alternate Energy Control Center (AECC) for disaster recoverability.

This project will include the replacement of the current replication system used by the Feeder Management System (FMS) with Virtual Machine platforms in order to improve the reliability and disaster recoverability of FMS. The new Virtual environment will upgrade the OMS computer systems with new servers, storage units and virtual infrastructure software to facilitate the operation of multiple virtual machines on fewer physical servers. Complete duplication of the production database functionality will be built in parallel with the current production database, allowing a cutover with a minimal system outage. The new architecture will build local and remote duplication into every aspect of the OMS, thus creating fault tolerant dual redundant systems.

Justification Summary:
This project is needed to maintain OMS computer system hardware and operating systems current with industry levels in order to maintain high system performance, better reliable systems and databases, strong cybersecurity posture and dual redundant, fully independent backup systems at the AECC.

Supplemental Information:

- Alternatives: None. Without hardware and software upgrades, the software system will become vulnerable and unreliable.

- Risk of No Action: Risk of greater hardware breakdown, less redundancy, less reliability and less secure systems.

- Non-financial Benefits: Fewer interruptions to the OMS system, more reliable systems, highly available functionalities and disaster recoverability.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable):N/A

- Basis for Estimate: Project scope, schedule, and vendor proposals, depending upon the kind of project required.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	41	6	95	87		50
M&S	-	-	-	-		0
A/P	157	167	182	162		307
Other	-	-	-	-		10
Overheads	34	10	63	53		60
Total	**232**	**183**	**340**	**302**		**427**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	70	70	70	70	70
M&S	-	-	-	-	-
A/P	168	260	270	270	270
Other	15	23	24	24	24
Overheads	36	37	36	36	36
Total	**289**	**390**	**400**	**400**	**400**

X	Capital
	O&M

2020 – Central Operations/System & Transmission Operations

Project/Program Title	OSS Phase 3
Project Manager	Irina Northrup
Hyperion Project Number	PR.23273891
Status of Project	Planning
Estimated Start Date	January 2020
Estimated Completion Date	December 2020
Work Plan Category	Operationally Required

Work Description:

The Outage Scheduling System (OSS) is used to submit, review, and approve outage requests on the electric system. This effort will enhance OSS with features critical for safeguarding the electric system reliability, supporting the electric equipment outage-dependent capital budgets of various Company organizations, facilitate compliance requirements and provide needed flexibility, transparency and improved user experience.

The major proposed enhancements are as follows:

- Interface with the NYISO's OSS to facilitate outage coordination;
- Interface with Primavera P6, Engineering's Project Management scheduling tool to better support the planning and implementation of construction projects;
- Upgraded interface with Maximo to enable automated transmittal of equipment status changes to OSS;
- Includes timeline structure associated with each outage request to facilitate compliance with outage notifications;
- Automate and integrate within OSS current manual flows and processes;
- Develop front-end modules for manipulating user-controlled parameters to minimize reliance on programmers and keep current with evolving requirements;
- Enhance and extend current functionality such as bulk actions processing to all users;
- Automate intelligent sequences such as dissemination of revised District Operator (DO) Reports upon changes in schedule, and preservation of switching statuses at the Scheduling DO level.

Justification Summary:

The main driver of the Phase 3 enhancements is a more efficient OSS that supports electric system reliability through better outage planning and delivery, and facilitates compliance notification requirements. These goals are achieved via the following:

a) Facilitates outage coordination: the interface with the NYISO scheduling system ensures a seamless exchange of critical outage information between the NYISO and Con Edison;

b) The Primavera interface focuses on better outage planning and implementation by enabling Company organizations to establish and achieve more accurate targets for capital expenditures and better coordination between the capital and the O&M compliance work. This interface also lays out a solid foundation for the pursuit of schedule optimization functionality in the future;
c) Assists with minimizing operating errors: automation of the Maximo–OSS interface enables the selection and validation of the current equipment impacted by the outage;
d) Ensures compliance with evolving requirements for NYISO, NERC, PSC, Transit and Railroad and High Tension customer notifications.

Additionally, this project will streamline, automate and integrate multiple manual tasks and flows thus assuring increased efficiency in outage scheduling.

Supplemental Information:

- Alternatives – Take no new actions and maintain the status quo.

- Risk of No Action - Maintaining the status quo does not provide any of the needed improvements in the outlined areas, would not address emergent issues, would not enable business changes and would not provide needed enhancements. For example, enhanced outage coordination, consistently achieving outage related capital budget targets, scheduling error minimization, elimination of lost outages due to missed notifications cannot be accomplished. Users will also be unable to keep OSS current with changes in outage notification requirements by external entities as well as changes in internal procedures whose stipulations are captured in OSS, and thus continue to be prone to failing compliance mandates.

- Non-Financial Benefits (if Applicable): This project ensures that reliability, safety and compliance with NYISO, NERC and PSC requirements are not only maintained, but enhanced and that more efficient work processing is achieved.

- Summary of Financial Benefits/Costs: N/A

- Technical Evaluation/Analysis: N/A

- Project Relationships (if Applicable): N/A

- Basis for Estimate: Project scope, schedule, and IT guidance

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	315	-	-	-
M&S	-	0	-	-	-
A/P	-	2,076	-	-	-
Other	-	185	-	-	-
Overheads	-	176	-	-	-
Total	**-**	**2,752**	**-**	**-**	**-**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Outage Management System Enhancements Phase III (OMS) Outage Management System Enhancements Phase IV (OMS)
Project Manager	Vinod Vemireddi
Hyperion Number	PR.22031585, PR.22885571
Status of Project	In Progress
Estimated Start Date	Phase III 1/2017 Phase IV 1/2021
Estimated Completion Date	Phase III 12/2020 Phase IV 12/2023
Work Plan Category	Strategic

Work Description:
The use of Outage Management Systems (OMS) and associated dashboards is critical to operators and other mid-high level decision makers to ensure the efficient assessment and response to incidents impacting service to our customers. Continued enhancements and integration of OMS systems with other technology is critical to ensuring continued focus on our customer needs. The Company continues to make significant improvements in its ability to quickly understand the number of customers impacted by power disturbances and provide customers with timely estimated time of restoration. These accomplishments were achieved through a series of process improvements and enhancements of the Outage Management suite of systems including STAR (System Trouble Analysis and Reporting). STAR is based on Oracle's Outage Management System software suite. Increased attention to providing timely Estimated Times of Restoration (ETRs) as well as enhancing the accuracy of customer impacts via the integration of OMS with Distribution Supervisory Control and Data Acquisition (DSCADA), and Advanced Meter Infrastructure (AMI) underlines the need to continue focus on outage management systems.

In 2017, new modules were purchased including: an Inter-Control Center Communications (ICCP) SCADA adaptor, training simulator and OMA (Outage Mobile Application). The Company is currently in various stages of customizing, developing and testing various aspects of these new features for integration into the overall OMS platform. Phase III of this project, which commenced in 2017 and runs thru 2020, also includes enhancements to existing applications (OMS and Switching) as well as configuration changes to new vendor releases. Phase IV is expected to commence in 2021 and will continue to build on the existing platform and as well as add new tools that are continually being developed as result of changing technology and grid modernization.

In May of 2018, Electric Operations completed the upgrade of the corporate OMS to Oracle's current standard version of NMS 2.3. This enables the Company to take full advantage of new enhancements offered by the product as well as ensuring adequate support in terms of service packs and patches. Con Edison has been taking progressive steps to improve how the Company responds to customer outages with new technology and tools that are flexible and functional. Enhancements include more visibility to outages to critical customers, including the MTA, due to an expanded critical customer fields, as well as various features that will support the upcoming OMS/AMI integration.
In keeping with its current 3- year upgrade schedule, the Company will look to upgrade to the most current version of the vendor's OMS product by mid - 2021. This enables the Company to take full

advantage of new enhancements offered by the OMS product line as well as ensuring adequate support in terms of service packs and patches from the vendor.

Going forward from 2019 through 2023, continuous efforts to identify and incorporate enhancements within the modules utilized by the OMS system will supplement efforts to better identify opportunities for enhanced operator training. The recent purchase of the training simulator will provide a tool for trainers to develop real time scenarios. These scenarios will be provided to trainees to assess their ability to utilize the various OMS tools to address the situations they are given to ensure they are addressed appropriately and that they are using all of the tools correctly.

In addition, collaboration with other utilities and vendors has demonstrated the need to regularly upgrade associated OMS hardware and software to remain in alignment with product improvements and changing industry technologies as well as avoiding exposure to unsupported hardware and software. In addition, there are other modules that are currently not utilized by the Company, that need to continue to be evaluated for further enhancements on how we do business. Expected growth and development in Distributed Energy Resources and REV initiatives is expected to drive opportunities for improvement in the OMS systems utilized by the operators in order to better understand the impact the effect of these systems on the distribution system.

To enhance operational excellence, the electronic switching module has been moved to production and is in various stages of utilization by the operating regions. During the 2019-2020 period, the Company is also looking to implement other modules that were procured as part of this project including enhanced SCADA integration with OMS, a training simulator and a mobile application. In 2018, a pilot application is being introduced that will allow field crews to directly update ETRs to customers without operator intervention. Providing field crews with direct capability to update ETRs is expected to result in increased ETR accuracy and as a result, increased customer satisfaction. Training operators in consistent use of the OMS products will not only result in enhanced customer experiences and increased operational excellence, it is also critical to supporting the Company's near-term vision of control center consolidation.

The OMS system relies heavily on the integration of customer information systems and the distribution electrical model to accurately "match" customers impacted by outages on the electric distribution system. Enhancements to the model will ensure accurate customer reporting as well as providing more accurate information to customers regarding ETRs. With the integration of both AMI and DSCADA into OMS, it is expected that model enhancements/improvements will be required to improve the overall accuracy of the application. This project will also include efforts to continue to seek improvements for making the model efficient through efforts related to managing the size of the model and through modifications to predictive logic and grouping rules specific to the integration of DSCADA and AMI into the OMS system

Justification Summary:
The enhancements summarized in the Technical Evaluation/Analysis detail how Electric Operations will utilize improved technology to respond to customer outages in a timelier manner, become more transparent with customers and increase operational excellence. Continued enhancements with the recently updated OMS system as well as future software and hardware upgrades will provide increased functionality to enhance day to day operations, storm outage response, and enable a more efficient process for planning and prioritizing work.

As part of this project going forward, enhancements to the various modules include: enhancements to the base OMS application, enhancements to electronic switching, AMI/OMS integration, development of the training simulator and increased usage of the mobile application for electronic switching and damage assessment. Initial AMI –OMS integration, which allowed basic manual pinging of AMI meters directly through the OMS, was completed in the 3rd quarter of 2018. One of the benefits of this effort is the transparency that this real time information will provide to our OMS system and the control room operators. This will provide better information to outage models for more accurate understanding of customer impact from events, especially on the network system, where there is very limited information currently available that allows operators to determine the extent of an outage more quickly than in the past. It will also provide the ability to better identify embedded outages as well as provide the operators to ping meters to minimize dispatch of resources to customer problems.

Remaining highlights of this project for Phase III include:
$ 1 million for OMS hardware upgrade in 2020
$ 3 million for enhancement to applications including: dynamic switching, AMI/OMS integration, training simulator and the further development of the mobile application

Supplemental Information:

- Alternatives:
  Other options for the OMS program would be to:
  1. Remain on the current version of OMS system, make no significant additions or enhancements, and rely on existing interfaces and functionality as well as older technology platforms.

  2. Identify a replacement for the OMS system with a competing outage management system. Acquisition and development costs as well as the costs associated with additional training for our operators are expected to be quite substantial if a replacement system were to be considered.

- Risk of No Action:
  Like many other software upgrades, there is generally a significant lag between the release of a vendor application and the implementation of that new system in a live environment. Because of the critical nature of an OMS application, significant integration and operator testing must be done within host environment before a "go-live". This lag can result in the go-live for an OMS upgrade being a couple of years after the vendor product release. By this point, vendors are already involved in development of new products to keep up with new technologies, integration platforms and customer requested enhancements.

  Over the last several years, the Company has made great strides in staying current with the vendor's release of upgrades to its OMS product line. The Company has generally operated on a 3 year cycle. It is imperative that we maintain that momentum and ensure that continuous maintenance, enhancements and evolvement are part of those efforts to maintain alignment with our peer utilities. With no enhancements the older technology will be difficult to maintain, as internal staff and vendor support personnel becoming no longer available to support existing products and systems. We want to ensure that we are utilizing the most cutting edge technology as it relates to new enhancements and features that are consistent with industry needs/drivers.

- Non-financial Benefits:
  The continued use and enhancements of the new outage management systems will continue to enable Electric Operations to efficiently evaluate, prioritize and manage electric outages on both

the network and non-network distribution systems. The use of the OMS system will continue to help facilitate improved outage impact assessment, response and customer communication.

- Enhance external relationships with our customers
- Reduce complaints to executives, elected officials, DOT, and PSC
- Improve coordination and communication within Con Edison
- More efficient use of field crews through the use of the AMI/OMS integration and mobile applications. The ability to integrate this new data stream with our OMS system to further improve the ability of operators to fully understand the problem and better serve our customers will be a large part of our efforts in this area. With the mobile application, field crews will be able to update ETR and receive and transmit switching orders

- Technical Evaluation/Analysis:

  Con Edison is committed to developing best practice outage restoration processes and information systems. These processes and systems help facilitate the correct assessment of customer outages, effective restoration planning, and timely return of service to customers. The Company continues to make significant improvement in its ability to quickly understand the number of customers impacted by power disturbances and provide customers with timely information on restoration times. These accomplishments were achieved through a series of process improvements and enhancements of the Outage Management suite of systems including STAR, which is based on Oracle's Distribution Management System software suite. The Oracle product continues to be one of the leading outage management software suites and is utilized worldwide by many large utilities. The technical evaluation considered the following activities that are expected to be evaluated and implemented over the upcoming years:
  - Implement additional SCADA to STAR functionality using XA/21
  - Continue to implement additional functionality available to improve the accuracy of customer ETRs
  - Implement AMI with the OMS to improve outage identification, grouping and dispatch.
  - Use of the mobile application to allow field crews to update ETRs, provide outage causes to customers and receive/transmit switching orders electronically
  - Investigate and implement improvements as required for Damage Assessment to enhance remote damage data capture and interfaces with STAR or other OMS solutions for the timely development of work plan and customer level ETR's.
  - Implement the Automated Switch Plans module of the Distribution Switching System (DSS) to improve the OMS process and development of the training simulator for operators.
  - Identify new testing and monitoring tools to cover all functionalities within OMS including model viewer and the overall IT health of the systems
  - Implement improvements to enhance training capabilities by creating more e-learning modules, and quick videos while providing additional in-class training for OMS processes and systems
  - Continue efforts to maintain alignment with major software release upgrades

- Project Relationships (if applicable):

  Other projects that have close relationships include all applications related to improving how the Company manages Customer interfaces and related communications including the Customer Project Management System (CPMS), Work Management System (WMS), the Outage Management Dashboard (BI) and external Customer Portal.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	303		566
M&S	-	-	-	16		2
A/P	-	-	-	3296		1,328
Other	-	-	-	31		61
Overheads	-	-	-	324		593
Total	**-**	**-**	**-**	**3,970**		**2,550**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	240	240	-	-	-
M&S	-	525	-	-	-
A/P	1,040	1,422	2,500	1,750	1,750
Other	92	173	-	-	-
Overheads	128	139	-	-	-
Total	**1,500**	**2,499**	**2,500**	**1,750**	**1,750**

X	Capital
	O&M

2019 Central Operations/System & Transmission Operations

Project/Program Title	Plant Information System
Project Manager	Joseph Del Re
Hyperion Project Number	PR.20335944
Status of Project	Planning
Estimated Start Date	January 2019
Estimated Completion Date	December 2022
Work Plan Category	Strategic

Work Description:
Two existing Plant Information (PI) servers are used as data repositories. PI is used by System Operation, hundreds of users and many operational, planning and analysis systems throughout the corporation. New virtual servers will be installed, the redundancy will be improved, the operating system will be upgraded and new application software will be installed.

Justification Summary:
The System Operation PI system is used for historical data archival and retrieval of EMS information, and for presenting the current status of equipment on the electric distribution and transmission system. The benefits of improving the PI system would extend to the many systems (in other organizations) that interface with PI, such as the distribution information system (DIS). System Operation's PI system is the official data archive for Central Operation's Transmission and Distribution systems and essential for the related planning, compliance, and support organizations to perform their functions.

The new servers will better support the new features available from the vendor that will allow multiple servers to be updated at the same time and to work as a high availability fault tolerant system. This capability will tremendously shorten the interruption time if the primary server goes down, as the other server will be up to date and available immediately.

Supplemental Information:

- Alternatives: There is no applicable alternative.
- Risk of No Action: Not replacing/upgrading the PI servers would jeopardize the availability of these servers, affect the availability of data made available to the hundreds of corporate users and systems and make it more difficult to implement regular maintenance work such as failover and patching. If not upgraded, the existing servers will not be able to keep up with the archival needs of the current EMS. Archival would need to be restricted or limited to extend life, leaving potentially critical data unavailable. New functionalities would not be provided and possibly, as a result, new security features would not be implemented.

- Non-financial Benefits: Reliability and enhanced visibility to corporate users and systems

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable): PI data historian is used by the energy management system (EMS). This project is planned to be completed and offer the new capabilities and functionalities in time for the EMS Replacement project.

- Basis for Estimate: The estimates were determined based on the cost of the additional licenses needed for such systems and amount of vendor involvement.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	50	-	-	50	-
M&S	-	-	-	-	-
A/P	164	-	-	175	-
Other	-	-	-	-	-
Overheads	26	-	-	25	-
Total	**240**	-	-	**250**	-

X	Capital
	O&M

2019 – Construction

Project/Program Title	Rogue Employee (GRC)
Project Manager	Alexandra Vinokur
Project Number	PR.21751551
Status of Project	Ongoing
Estimated Start Date	N/A
Estimated Completion Date	N/A
Work Plan Category	Strategic

Work Description:
Construction will collaborate with Business Controls Auditing (BCA), and Information Resources to pilot the use of the Oracle Governance Risk Control module (GRC).

The Company will implement an electronic monitoring tool which allows Construction transparency to analyze payment related database transactions for segregation of duties, audit trail, changes for system configuration, review of unusual use of item transactions, and create rules and workflows for Oracle EBS based forms and non-Oracle systems such as Compass, and POCR. This will be used to mitigate Construction risks and Oracle reporting as outlined in the Construction's Business Plan.

The scope will include the following process areas:
1) COMPASS Complex Service Purchase Order (Oracle EBS) – Work Confirmations
2) Duplicate Contractor Payments via Oracle EBS Receipts
3) Duplicate Contractor Payments via Multiple GOI's
4) Public Improvement – Roles and Responsibility Assignment (Oracle EBS)
5) Contract Administration- POCA_POCR Roles and Responsibility Assignment (Oracle EBS)
6) Segregation of Duties – Oracle EBS Responsibility Assignment
7) Non-invoiced Receipts – Oracle EBS
8) Contract Administration – POCA_POCR COMPASS BPA Extensions /Amount Limit changes
9) Contract Administration – POCA_POCR COMPASS Complex Service PO Changes
10) Role and Responsibility Cross System Review (Oracle EBS/COMPASS/POCR/LOT)
11) Macro/Micro Review of COMPASS Items on BPA Releases (Oracle EBS)
12) Identification of Active COMPASS Suppliers (Oracle EBS)
13) Reconciliation of Oracle to Compass Payments by Payment Stream

Benefits:
- Continuous monitoring of Oracle EBS employee access
- Reduce unauthorized transactions by limiting the risk of allowing conflicting responsibilities
- Improving transparency by tracking system configuration changes
- Increased visibility and continuous monitoring of Oracle EBS transactions

- Ability to view incomplete transaction cycles
- Identification of duplicate contractor payments
- Improved receipt and accrual accuracy
- More timely contractor payments
- Simplifying transaction analysis by targeting parameters with key weaknesses
- Reduced dependence on EBS Support and IR

Justification Summary:
This will be used to mitigate Construction risks and Oracle reporting as outlined in the Construction's Business Plan.

Supplemental Information:

- Alternatives: Customize Oracle or Manual sample testing

- Risk of No Action: Increase risk for potential fraud, non-identification of inherent System weakness, detail lacking reports

- Non-financial Benefits: Time savings, Improved contractor relationships, Proactively prevent fraud

- Summary of Financial Benefits (if applicable) and Costs: NA

- Technical Evaluation/Analysis: NA

- Project Relationships (if applicable): Oracle E-Business Suite (EBS), COMPASS, POCR/POCA System, LOT

- Basis for Estimate: The estimate below is based on historical spend for Oracle Enterprise Business Suite configuration.

Total Funding Level ($000):

Historical Elements of Expense
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-				
M&S	-	-				
A/P	-	-				
Other	-	-				
Overheads	-	-				
Total	-	-	**211**	**224**		**275**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor					
M&S					
A/P					
Other					
Overheads					
Total	**180**	**200**	**200**	**200**	**200**

X	Capital
	O&M

2019 – Central Operations/ Substation Operations

Project/Program Title	Substation Technology Improvements Program
Project Manager	Matt Walther
Hyperion Project Number	PR.1ES7500
Status of Project	In-Progress
Estimated Start Date	N/A
Estimated Completion Date	N/A
Work Plan Category	Strategic

Work Description:
This program funds the technology improvements needed to upgrade, enhance, automate, and/or establish substation processes with the goal of increasing efficiency and improving reliability. Substation Operations has established numerous procedures, instructions, and guidelines to ensure the safe operation and maintenance of the equipment. Many processes were developed to provide adherence to a course of action, involve data/information collection, transfer and storage. As technology advances, this program serves to identify and take advantage of opportunities to improve the efficiency of these processes by implementing new tools or upgrading existing ones to enhance how data is collected, transferred, and/or stored. For example, software enhancements were made to Datasplice, a work management tool, to improve how equipment functional test results were documented making it easier to track equipment test failures and facilitating faster recovery time and implementation of compensatory actions.

Justification Summary:
The implementation and upgrade of new technology is instrumental to allowing Substation Operations to continually improve efficiency and reliability. The use of technology to streamline processes results in a better resource utilization and a reduction in task time requirements. Better data collection and storage facilitates enhanced data analysis and trending, which ultimately leads to improved reliability and equipment performance.

The quickly expanded role of mobile solutions in the work area are driving continued investment in technology to improve efficiency and help drive down costs. The existing projects listed here that are funded under this program all represent a continued effort by Substation Operations to leverage technology to automate processes and improve the collection and analysis of data to drive business decisions. As the use of technology in the workplace grows, the funding of this program at an incrementally higher amount vs. historical spend is necessary to support this growth.

The typical lifecycle of these software systems is approximately four years such that a platform upgrade is necessary to ensure the continued reliability of the system. Datasplice and SmartProcedures systems have just completed major upgrades. An upgrade to the Engage platform is not yet planned. Funding for any system upgrades is typically provided by this capital program.

DataSplice: DataSplice is a work management software that works with Maximo to gather important equipment inspection and maintenance data. DataSplice provides functionality not available in Maximo and greatly enhances our ability to improve maintenance practices and track and trend equipment conditions. Customization of this software is performed to expand functionality with the goal of improving maintenance effectiveness.

The DataSplice servers were replaced with software upgrades to a web-based version that will ensure its continued success and reliable operation. This project will continue as enhancements to the web-based version and will be implemented. Enhancing the software functionality will guarantee critical software operational needs will continue to be met. Mobile computing capabilities, such as the use of IS devices, will improve data collection capabilities and accuracy and allow continued asset management practices improvement as well as contribute to maintenance efficiency and productivity. Functionality will be created to utilize Geographic Information Systems with Datasplice on a mobile platform with the goals of improving access to information in the field. For example, field crews will be able to easily find available work in their proximity and open the applicable inspection form from that location. They will also be able to view reference documents including videos in the field to improve their work execution and reduce errors. We are also going to leverage these capabilities to improve the equipment operating orders process. GIS and mobile technology will enable the automatic identification of equipment and direct Operators what steps to perform thereby helping to reduce human performance errors during this process.

Engage: Engage is an asset management software that works seamlessly with Substation Operation's work management system, Maximo, to facilitate maintenance resource management, planning, scheduling, and work assignment. The software is part of an integrated asset management platform that links other asset management databases and functions to improve maintenance and engineering efficiency.

During development of the Engage platform, we identified additional processes and databases that are currently disconnected from the core asset and work management processes housed on the Engage platform. Incorporation of these processes and databases will enhance the user experience and result in productivity and efficiency improvements. For example, tracking SF6 leaks and usage was a manually intensive, error-prone process that was performed using Excel spreadsheets. An SF6 Management module was created in Engage to automate the calculation of equipment leak rates so that leak repairs could be prioritized and to calculate monthly and annual SF6 emissions. Creation of this module has greatly reduced the manual burden of calculating leak rates and emissions, improved accuracy, and helped Substations to achieve SF6 emission improvements. In addition, functionality critical to the effective use of the system by certain work groups within Substations is missing. For example, the daily and long-term management of capital projects differs from routine maintenance. Functionality in Engage was created to facilitate better management of capital projects by creating the ability to compare project resource needs vs. resource availability over the course of 6 months or more. This capability allows the work groups to more effectively coordinate and execute work. Further development of more user targeted functionality as part of Engage will enable all user groups to effectively use and benefit from the system. Work on Engage is expected to continue for the next few years, with the integration of other work management functions, project management and time management tools / performance metrics continuing.

Smart Procedures: This project converted all Substation Operations Word document procedures into a database format. The advantages gained include a reduction in labor needed to maintain procedures, more accurate procedures, faster response times to change requests, and greater flexibility in accessing and utilizing procedures.

Software enhancements are being made to this system to improve search capabilities, facilitate integration with work management systems, and automate equipment inspection forms. The system is also being updated to enable the conversion of Engineering specifications and System and Station descriptions. This work will help to reduce the amount of time needed to update these documents as well as enabling the ability for other systems, such as our work management systems, to interrogate the data so that users can easily find needed information.

Data Acquisition Network (DAN): The goal of this project is to establish a standard for housing data acquisition applications on a secure and dedicated infrastructure environment and to migrate existing systems onto this platform. This effort will develop a secure, Verizon wireless VPN dedicated network segment with secured communications over SCADANet Infrastructure hardware, server, and storage and networking equipment, will be procured and configured accordingly. The establishment of a secure, dedicated network for data collection applications will enable Substation Operations to install and utilize remote equipment monitoring devices for the purpose of automation of manual reading collection and to monitor the condition of equipment. An example of this is the automation of pump house tank level readings that are currently collected manually by Operators each day. Significant time savings are anticipated once we are able to electronically gather these readings leveraging the secure environment provided by the DAN.

Supplemental Information:

- Alternatives: No applicable alternative

  Datasplice - Do not enhance DataSplice. This option is not recommended, since enhancing the software functionality will guarantee critical software operational needs will continue to be met. Functionality to leverage mobile computing capabilities is necessary to improve data collection capabilities and accuracy and allow continued asset management practices improvement as well as contribute to maintenance efficiency and productivity.

  Engage- During the course of the Engage project, other work management systems have developed and offer similar functionality for certain parts of the platform. These features will be evaluated to ensure we only develop applications that are not redundant or at an incremental cost.

  Smart Procedures – No applicable alternative. The Smart Procedures project was successfully implemented and the proposed enhancements will provide additional benefit and cost savings.

  Data Acquisition Network – No applicable alternative. The existing remote monitoring applications remain vulnerable to cyber-attacks. The future remote monitoring applications will likewise live in a vulnerable environment.

- Risk of No Action: The alternative of taking no action is not recommended. Technology improvements are necessary to ensure existing systems work as designed and originally intended. The failure to do so could render the systems obsolete. Other improvements are necessary to support process changes intended to improve efficiency and productivity of maintenance and operations.

- Non-financial Benefits: Several of the applications supported here, such as Engage, Datasplice, and Smart Procedures are expected to enhance system reliability. Engage is used to strategically track and deploy Substation Operators, ensuring they are needed as required to change equipment status in order to maintain the overall integrity of the Con Edison electric system. Datasplice and Smart Procedures are both used to enhance our maintenance programs, in an effort to ensure equipment outages are minimized.

- Summary of Financial Benefits (if applicable) and Costs: Most of the applications noted here help reduce overall operations and maintenance costs throughout Substation Operations. Engage is geared towards ensuring that work is efficiently planned, that all parts and tools required for a job are available before the job commences, and that supporting materials such as procedures and equipment manuals are all readily available to work crews. Datasplice is used to streamline data inputs to our Work Management systems, and Smart Procedures will reduce labor costs associated with updating and maintaining procedures required for use in the field.

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable): N/A

- Basis for Estimate: Funding request is based on historic actual costs of similar initiatives done under this program line.

Work Plan:
2019: The Engage and Datasplice projects will continue to incorporate work activities and equipment condition tracking processes such as hot spots in order to improve effectiveness of the process. There will be more focus on leveraging mobile solutions and automated planning, scheduling, and work assignments.
2020: The Engage and Datasplice projects will continue and will incorporate work necessary to support the planned Maximo upgrade. Completion of the Data Acquisition Network (DAN) project is planned.
2021: Following completion of the DAN project, a large emphasis will be towards the installation of remote monitoring technology such as pump house automation as this will help lower operating costs. In addition, we plan to automate dielectric facility operating orders and work permits. It is also anticipated that work will be done to incorporate robotics technology for distribution level breakers (the robotics development is currently an R&D effort).
2022/2023: Future work includes automation of all operating orders and work permits to leverage mobile solutions as well as the incorporation of robotics in distribution stations and drones in outdoor stations for the purpose of performing infrared and visual inspections.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	138	51	12	35		133
M&S	15	326	36	288		844
A/P	943	607	653	-		1,241
Other	28	5	84	4		651
Overheads	152	133	128	375		378
Total	**1,276**	**1,122**	**913**	**702**	**-**	**3,247**

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	787	165	300	300	300
M&S	532	110	200	200	200
A/P	2,310	451	820	834	826
Other	268	53	106	101	100
Overheads	1353	321	574	565	574
Total	**5,250**	**1,100**	**2,000**	**2,000**	**$2,000**

X	Capital
	O&M

2019 Capital - Central Operations/System & Transmission Operation

Project/Program Title	System Operation Enhancements
Project Manager	Richard Scholz
Hyperion Project Number	PR.21925929
Status of Project	Ongoing
Estimated Start Date	January 1998
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:
These enhancements will allow the District Operators at the energy control center (ECC) and alternate ECC (AECC) to issue groups of operating orders to various field operations groups through an automated process using predefined sets of operating orders based on standardized jobs. Major software changes and new applications need to be developed to support this enhanced processing sequence and its system dependencies. This project provides tools and applications that focus on improving the operators' effectiveness, helping to reduce manual transfer of data between systems, provide automated guidance when actions are necessary, and check work orders against predetermined rules to ensure proper instructions are given to field organizations.

This project will further automate parts of the electrical operating order process by utilizing a computer directed format to set up an automated sequence of operating orders. This will be accomplished by making use of existing systems and through the deployment of new interfaces. These systems, new and existing, will interface seamlessly with one another. For example, an Out of Service Work Permit (OSWP) request application that is given to the control center by email and manually transferred by the operator will now be directly uploaded into Feeder Management System (FMS)/ Transmission Operation Management System (TOMS) for the District Operators to review and process, helping to eliminate the manual data transfer step.

Justification Summary:
The District Operators perform over 500,000 operations per year. The sheer volume of work, coupled with the complexity of the systems, the variety of equipment types, and associated set of operating rules and requirements make the District Operators' job extremely challenging. The District Operators coordinate and directs all switching operations and permits to work on Con Edison's transmission and distribution systems, ensuring safety to personnel and safe operation of equipment while minimizing downtime.

These process automation enhancements will improve the operating environment by eliminating routine handoffs, allowing the District Operators to devote more time to analyzing complicated situations thoroughly prior to issuing orders. This reduces the opportunity for an operating error while also improving feeder restoration time.
These enhancements will support the effort to continuously improve our operating efficiency by increasing the productivity of field and substation personnel as well as reducing feeder-processing time.

Supplemental Information:

- Alternatives: The only alternative is to run the current system as is.
- Risk of No Action: Less efficiency and flexibility to work with changing field processes, less reliability and less secure systems.
- Non-financial Benefits: Safer operating environment; safer field switching; more productivity.
- Summary of Financial Benefits (if applicable) and Costs: N/A
- Technical Evaluation/Analysis: N/A
- Project Relationships (if applicable): N/A
- Basis for Estimate: Project scope, schedule, and vendor proposals.

Annual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	56	69	31	19		100
M&S	0	0	0	0		0
A/P	143	232	322	370		200
Other	0	0	0	0		0
Overheads	43	63	26	18		32
Total	**242**	**364**	**379**	**407**		**332**

Future Elements of Expense:

EOE	2019	2020	2021	2022	2023
Labor	30	30	30	30	30
M&S	0	0	0	0	0
A/P	241	246	253	352	352
Other	0	0	0	0	0
Overheads	18	17	17	18	18
Total	**289**	**293**	**300**	**400**	**400**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	Work Management System (Sustainability)
Project Manager	Leo A. Scally
Hyperion Project Number	PR.21322418
Status of Project	In Progress
Estimated Start Date	Q1 2019
Estimated Completion Date	Q4 2021
Work Plan Category	Strategic

Work Description:
Governance and Sustainability continues as an on-going part of the Work Management solution. Governance will include addressing application defects as found during utilization of the core CGI-Logica ARM Suite of applications, as well as defects found during utilization of interfaces to various other application systems such as Oracle Project Accounting, Oracle Labor Distribution, the Energy Services (CPMS) Pega application, HR Payroll PeopleSoft, LayOut Tracking (LOTs) system and PowerPlant and other applications that use the BizTalk and/or other customer-built interfaces.

Governance includes the following tasks:

- Prioritization, recreation, documentation of defects, testing of the remedies provided by CGI-Logica or technology support groups and the implementations of the defect solutions as moved into the production stack through the various test environments.

- Addressing defects in reporting applications and prioritization and documentation of these defects. In addition it is anticipated additional business type reports will be requested or modifications to existing business reports (compliance, operational, productivity) by the Business Users as they become more familiar with the applications and business methods evolve.

- License & Maintenance costs for Logica ARM Suite, Oracle Server, MapPoint, MS Info Path Forms Builder and other applications required for continued use of the various systems and applications.

- Updating the Learning Center training courses and proficiency test materials for all application modules as well as revising the online and hard copy training manuals. Development of Job Aids, and Tips & Tricks. Continuation of the Change Management initiative to ensure Super users, Subject Matter Experts and managers are supported and highly engaged in all aspects of process change, organization restructure and application enhancements.

- Continuation of Compatible Unit (CU) Simplification effort to reduce burdens on users when doing "as-built" designs and construction.

Further requirements for enhancements to the CGI-Logica application and interfaces will be required as the Customer Information System (CIS) is replaced and the implementation of a Graphical Information

System (GIS). Additional reporting in Oracle BI by modification of Oracle Project Accounting interface will also be reviewed and implemented where feasible. A more effective solution to "Tableau" data analysis and reporting is being reviewed will be considered with a possible migration to the Oracle BIEE reporting environment.

Value Realization

- Continued report generation to support Field Crew productivity metrics around standard design hours and comparison to actual constructed hours. Metrics for Engineering Design productivity and accuracy of design components.

- Modification of design standards hours to account for new expectations and new as-built construction actual hours. Refinement of unit hours and costs to for Engineering Design Estimates.

Report Generation

- Continuation of developing report requirements, designing new reports, testing of reports and deployment of reports to meet business needs.

- Reports functions to include compliance reports, operational reports, productivity reports as well as report dashboards as required by business users.

CGI Enhancements for Business Users include:

- Design linkage to update the burdens/overheads/labor rates/contracts to make Logica estimates less dependent on manual table updates and improve accuracy

- Productivity analysis at the Work Request level to be provided by a reporting tool allowing Financial Managers to identify a Work Request with significant errors or incorrect Field "as-builts".

- Advancing the flexibility of the Work Order number field with Time Reporting so charges can be made to different L2s/L3s on the same Work Request for certain work items

- Enhancing the STAR Referral interface to automatically build out a WR based on required data entry by the STAR user making the referral. This will eliminate manually building out the WR.

- Creating an Open Main prioritization interface to update Open Main WR's based on changing system conditions. Today this is a manual effort that does not respond to changing system conditions.

- Adding a mechanism to better capture parking data and use that data to create a more effective work schedule.

- Enhanced visibility within ARM Scheduler if required pre-requisites have been managed to minimize false starts. Present false start rate is about 40% for underground and cable type work.

- New Route Sheet reports that will allow users to provide better visibility into the scheduled work and if pre-requisites have been met

Power Plant

- Improved automation to provide better visibility and root cause analysis to identify the source of the "kick-outs" that have to be manually processed between WMS and PowerPlant. This is a function of legacy data being in a free entry format.

HR Payroll

- Improvements and generation of automatic error reporting to provide a more targeted form of payroll issues that result from WMS batch reporting. This would reduce the manual efforts required between WMS and HR-Payroll to reconcile the weekly payroll processes and limits of items such as expenses and vacation allowances.

Financial Data Warehouse

- In addition to the data passed through the standard processes to Oracle BI through Project Accounting, more granular business information may be required that is only available in the WMS system. Although WMS is not a financial system, a common data store may be required to accomplish additional business requirements such as forecasting that may necessitate accessing (directly or indirectly) WMS data.

Justification Summary:
The Work Management Project including process change, organization restructuring and the deployment of CGI-Logica ARM Suite (Work Manager, Scheduler, Central Configuration, Asset Manager and Mobile Field Manager) completed project implementation at the end of the 4th quarter of 2014.

In 2015, the Work Management Governance team concluded a Gap Analysis review. The Governance team focused on several findings. These findings included enhancing Management Engagement through various checklists and process implementations, Compatible Unit (CU) Simplification to develop and group Compatible Units into larger Master Unit sets, process refinement for Time Reporting and Approval functions, Technology review and refinements for Mobile and core applications. In addition the development of the Model Office Initiative was deployed throughout the various regions to implement best practices and process compliance.
The team initiated quarterly deployments of CGI-Logica release to address known defects and enhancements to the application.

In 2018, new hardware will be deployed including implementing EXADATA servers to replace aging servers, implementing new software with visualization capability that will visually represent where the work is located. There are approximately 25-35 CGI-Logica requests to change the core application implementing findings from the Business Cost Optimization (BCO) teams and Capstone initiatives. In addition, there are hardware costs to address server hardware and licensing, new requirements for Customer Excellence initiatives, and Asset Manager Analytics for facility optimization.

Supplemental Information:

- Alternatives:
  Not taking advantage of known system defects or user requested upgrades, diminishes the effectiveness of the application and jeopardizes user support and use of the application.

- Risk of No Action:

  Failure to take corrective action on known defects jeopardizes the stability of the application. Not taking advantage of user change requests eliminates any productivity gains that could potentially be realized.

- Non-financial Benefits:

  Streamlines and improves work-flows and processes.

- Summary of Financial Benefits (if applicable) and Costs:

  One area of functionality improvement to the CGI ARM Suite addresses improved Pre-requisite management. This will allow field workers to identify pre-requisites that are needed to work at a location such as a manhole. It allows work schedulers to better request the needed pre-requisites, and track the status of those pre-requisites. The enhancements will warn the work schedulers when pre-requisites needed have not been completed. This eliminating the scheduling of crews to jobs that are not ready to be started. This new functionality will also help to reduce delays crews experience when in the field.

  Newly created reports eliminate the time spent by personnel in each field section manually tracking hours of work performed by crews against budget goals. These reports provide readily available information such as;

  - Last week's comparison of the SCHEDULED Capital, O&M, and Retirement hours targets compared to the actual hours charged.
  - Present week's comparison of the SCHEDULED Capital, O&M, and Retirement hours targets compared to the actual charged.
  - Forecasted scheduled work for next week compared Capital, O&M, and Retirement hours targets.

  There is also a trend chart to track the YTD progress of a particular section over the 52 week budget cycle compared to the YTD targets.

- Technical Evaluation/Analysis:

- Project Relationships (if applicable):

  Oracle BI, STAR Outage Management System, Oracle Project Accounting, Oracle Labor Distribution, the Energy Services (CPMS) Pega application, HR Payroll PeopleSoft, LayOut Tracking (LOTs) system and PowerPlant

- Basis for Estimate:

  The estimate for this project is based on the historical cost of performing similar work.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	2		-
M&S	-	456	130	3,554		485
A/P	-	1,812	926	302		58
Other	-	-	87	6		54
Overheads	-	23	21	63		10
Total	**-**	**2,291**	**1,164**	**3,927**		**608**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	472	1,475	1,475	1,475	1,475
M&S	-	-	-	-	-
A/P	275	755	764	764	769
Other	24	67	68	68	69
Overheads	228	703	693	693	689
Total	**1,000**	**3,000**	**3,000**	**3,000**	**3,000**

X	Capital
	O&M

2020 – Electric Operations

Project/Program Title	WMS-Phase II & Enhancements
Project Manager	Leo A. Scally
Project Number	PR.22844294
Status of Project	Post Production Support
Estimated Start Date	Q1 2018
Estimated Completion Date	Q2 2020
Work Plan Category	Strategic

Work Description:
The Work Management System (WMS) will be upgraded to the next major release of CGI's WMS software. This new software upgrades the key application called Work Manager from PowerBuilder technology to HTML 5. Another major improvement is the upgrade of Design Revision Navigation (DRN) to HTML 5. DRN is the tool used by Designers and Clerical to build out Work Requests (WR).

The CGI Field Manager application will be replaced with a new mobility solution. The mobility solution will add new modules for the Field Supervisor, Contractors, and Contractor Management. The field supervisor will now be able to see:

- The location of their crews
- How the work the crew performed breaks down to capital, maintenance, and retirement
- Where their crews will be working in the upcoming days so the supervisor can pre-inspect the location

The features of the Crew Mobility solution are as follows:

- Ability to store Facility/Component/Condition information on device for region being worked
- Ability to work in a disconnected state
- Ability to define screen configuration for what will be displayed
- Ability to work on Android, Apple, and Windows based solutions
- When adding a facility to the As Built…also have visibility to the open conditions on that facility and last results
- GPS Bread crumb trail tie to work location to the route the crew has taken and their present location
- Ability to edit facility/component attributes
- Ability to sketch (splice ticket drawing) and attach to WR
- Ability to take pictures and attach to WR and or facility
- Ability to pull job back before end of shift to make corrections
- Add a facility to as built
- Ability to see all open conditions on a facility
- Ability to close an open condition on a facility and send a message to Asset Manager to close that condition
- Ability to create a condition directly in the field

- Ability to copy a condition
- Add a point
- Add a span
- Add a Compatible Unit (CU)
- Enter an ad-hoc inspection
- Enter step based inspection from a WR
- Enter form based inspection from a WR
- Home screen that shows all scheduled work
- Add/Delete a parking restriction for a facility
- Report crew time
- Report As-Built
- Report time and as-built on same screen
- Visibility in Field Manager to work being CAP, O&M or RET when reporting time
- Find work location (GPS and map)
- Ability to adjust who is on the crew and the truck being used
- Ability to partially complete an inspection (Survey Areas)
- Ability to send schedule revisions to Crew
- Ability to view complete work history at a facility

The new Field Supervisor Mobility Solution will have all the features of the Crew Mobility solution plus the ability to see where the crews actually are in comparison to the assigned work location. The Field Supervisory mobility solution will also allow a supervisor to see the type and location of the upcoming scheduled work. This will allow a Field Supervisor to pre-inspect a location to better prepare for the scheduled work. The Field Supervisor will also have the ability to correct the parking (location, information, restrictions??) for this upcoming work if the supervisor finds that the stored parking information is incorrect.

The features of the Supervisor Mobility solution are as follows:

- All features available in the Crew Mobility solution
- Ability to create a condition directly
- Ability to copy a condition
- View time reported by crew by CAP, O&M or RET
- Adjust time reported by crew
- Adjust/Approve as-built before sending to Work Manager
- Adjust/Approve time before sending to Work Manager
- Find crews location (GPS and map)
- Home screen that shows each crew and their scheduled work (need to define fields)
- Visibility into next x days schedule for crews
- Add/Delete/Modify a parking restriction for a facility for work planned for future date
- Ability to see status of Crews AB during shift…CU, WC, truck location, and time reported
- Ability to enter an end of shift comment for the WR and a mechanism to track how many jobs were done and how many were not
- Ability to adjust who is on the crew and the truck being used
- Ability to see a crews schedule revisions

Contractors will now have the ability to interact directly with the WMS application from the field to report work status such as inspections and construction related work. The contractors will do this on standard mobile devices without the need for back office data entry and building interfaces. The Contractor Management module will allow Con Edison personnel to approve the contractor work and potentially allow for triggering contractor payments. The new Contractor Mobility solution will provide a flexible framework for a field contractor to enter data directly into WMS without the use of back office data entry or custom IT solutions. This is intended to be used by contractors doing inspections as well as construction. At this time, we do not foresee Construction management contractors using this solution.

The features of the Contractor Mobility solution are as follows:

- Home screen that shows all scheduled work
- Add a facility to as built
- Add a point
- Add a span
- Add a CU
- Find work location (GPS and map)
- Enter an ad-hoc inspection
- Enter step based inspection from a WR
- Enter form based inspection from a WR

The upgrade includes switching to a new database hardware and acquiring hardware to build new environments to support the testing of this upgrade. The devices that the crews use for the mobile application will also be upgraded. The new devices will be either new Toughbook models with better touch screen capability or toughpads.

Together with the Gas Work and Asset Management (GWAM) project, we will partner to purchase a mobility platform (MEAP – Mobile Enterprise Application Platform) that will enable us to better design and deliver the new mobility solution.

Asset Manager also gains added functionality such as multi-level hierarchy's and the ability to trigger inspections based on an attribute of that facility.

ARM Scheduler will also receive improvements that will allow Work Resource Management (WRM) the ability to split Work Components (WC) and move Compatible Units (CU) to the new WC. Today, users need to exit the ARM Scheduler, launch Work Manager, search for the WR, split the WC, move the CU's, save, then re-launch ARM Scheduler. A second improvement to ARM Scheduler will show the time charged to a WC and the remaining time on that WC. This will provide visibility to WRM on how much work is remaining or if the time allotted has been exceeded.

The summary of the additional functionality is as follows:

- Allow configurable Response Message in addition to standard MSG_RESPONSE
- Log Viewer Re-submit
- User Session Tracking by Server Id
- Work Manager MsgQue.exe Enhancement
- Field Manager (FM) Console
- Export Search Results for all List and Search windows
- Improved ARM Scheduler Load

- Text Messaging in Scheduler
- Safety Check in Scheduler
- Exporting Crew Management Details from Resource Management
- Ability to apply attachment details to ARM Scheduler hosted work
- Ability for controlling when work is transmitted to Field Manager
- Filter work list based on selected field within Field Manager
- New Survey Area Messages for Asset Manager
- Contractor Access to and Creation of Web Work Manager Business Case Authorization

Attachments
- Web Work Manager Work Component List Page Condition ID
- Work Request Search Restrictions
- Permit Associated Enhancements
- Mass Update for Work Category on Work Requests
- Add Work Request Owner to the Web Work Manager Work Request Detail Page
- Add Scheduling Polygon to the Web Work Manager New Work Request Page
- Attachments for Facilities/Components/Survey Areas
- Attachment Display and Update Rules
- Official Design Revision Work Component Creation Material Only Compatible Unit

Assignment Change
- Use the Start Date for Calculating the Next Due Date
- Street Index
- CIS Search
- Permit Attachment and One Call Information on Mobile
- Maintain Contacts on Web Portal
- Pass Step Result Comments to Work Request
- Multiple Drag Drop for Web Scheduling
- Cancellation of Redundant Work Requests
- Step Result User Exit
- WR Generation Based on Condition Type Constraints
- Update Procedure Version on Scheduled Work Requests
- Additional Fields for Field Manager Work Lists
- Calculate Due Date Based on Start or Complete Date
- Condition attachments required and number of attachments
- Field Type for ARM Scheduler Custom Fields
- Parent Requested Completion Date and Due Date Calculation
- Provide the Capability to Sort Data with Multi-Level Sorts in Field Manager
- Allow Begin of Shift onto Different Device when End of Shift Not Performed
- Synchronization of Earliest Start Date and Earliest Appointment Start Date
- Field Manager Procedure Reporting Cursor Placement
- Additional Mandatory fields for Work Request Types and Condition Types
- Copying Additional Permit Fields
- Dynamic Segmentation Messaging
- Updating Condition Detail that is Not the Latest
- Display Compliance Related Forms in Work Manager
- Work Component Creation Material Only CU Assignment Change

- Added New Work Manager Module
- Added Monitor Module
- Added Asset Investment Planner Module
- New Field Manager Lite Module
- Warranty Information
- Linear Assets
- Multi-Level Hierarchies
- Added Spatial Module
- Assigning X/Y Coordinates to Procedure Step
- Complete Inspection Related Work and Not Calculate Due Date
- Determine Frequency Rule Based on Attributes
- Determine WR Type / Sub-Type Based on Attributes
- Equivalent Procedures for Condition Follow-ups Related to a Facility and Vice-Versa
- Equivalent Procedures for Survey Areas
- Enhanced Navigation
- View All Work for a Facility
- Parameters Tab on the Survey Area Window
- Documentation Management
- New Work Manager Additional Capabilities
- ARM Scheduler Enhanced Update Notification
- ARM Scheduler Manage Jeopardy Alerts
- ARM Scheduler Link to External System
- ARM Scheduler Enhanced Spatial Viewing
- ARM Scheduler Enhanced Spatial Street Level Routing
- ARM Scheduler Enhanced Functionality for Find Window

Justification Summary:
PowerBuilder use peeked in the late 1990's. Converting Work Manager to HTML 5 will greatly improve the user experience by providing multiple views or windows on the screen to see work in various stages. The use of HTML 5 will also allow the configuration of these screens according to a user's role in the application. We will now be able to configure the view for designers to be very different that the view of construction personnel.

Today using DRN to build out Work Requests can be a time consuming task. DRN built within HTML 5 is expected to reduce the time necessary to build out a WR.

The CGI Field Manager application is used by field crews to report units of work, time, inspections, etc. Field Manager is cumbersome as it requires multiple steps to process this type of data. By replacing this mobile solution with a more streamlined mobile solution to greater improve the user experience. This improved user experience will then lead to improved input accuracy and work closure. There are two modules that comprise CGI's Field Manager. One is used by the field crews and the other is intended to be used by the field supervisor. There will be four Mobility modules:

- Crew Mobility
- Field Supervisor Mobility
- Contractor Mobility
- Contractor Supervisor Mobility Solution

The crew Field Manager is actively used but is also cumbersome and requires multiple steps to use basic functions. Crew Field Manager also requires time reporting and work unit completions on two different screens. Neither of these screens gives a clear understanding of how the work and time reported affect capital, maintenance, and retirement.

The Supervisor Field Manager has very few features and is of limited use to Field Supervisors. As a result, it is not used by Field Supervisors. The new Field Supervisor Mobility Solution will have all the features of the Crew Mobility solution plus the ability to see where the crews actually are in comparison to the assigned work location.

Electric's contractor use of WMS is limited to back office data entry of inspections completed in the field on paper or a custom IT solution developed and maintained by the contractor. Some of this data is entered into WMS but some is not such as Stray Voltage testing data. The Contractor Supervisory Mobility Solution will allow Con Edison personnel responsible for monitoring the contractors to review and approve the work completed by the contractor. We will evaluate a possible integration to Oracle to approve contractor pay items, but this may make WMS a SOX system.

The additional functionality added to Asset Manager includes multi-level hierarchies and the ability to trigger inspections based on an attribute of that facility.
The new WMS upgrade, these can be completely managed in the WMS application. An example of work that this would apply to would include; the inspection cycle of the Underground Transformers and its associated equipment is based on its location such as an isolated network, tidal location, or if the transformer feeds an essential service. Today, these cycles are driven by a field called CRITICALITY. The criticality field is just a number. It provides no intelligence as to what the value means. We intend to replace the CRITICALITY concept with a Facility Attribute dropdown. This dropdown will be very descriptive as to its reason for inspection. The system will generate the inspection due date on this descriptive attribute rather than just a number. We could also drive to drive to different account numbers based on this attribute as well.

Supplemental Information:

- Alternatives:
  Not taking advantage of known system improvements and defect corrections diminishes the effectiveness of the application and jeopardizes user support and use of the application.

- Risk of No Action:
  Efficiencies and productivity gains built in to the new upgraded software will be missed.
  The WMS Upgrade and the new Mobility solution are significant improvements to the way the WMS Application operates today. Clerical staff and designers will see a vastly improved Work Manager tool that will increase their productivity and user experience while also providing better visibility into the work they need to manage through improved views. The new Mobility solution will provide a streamlined platform for the Con Edison Field Crews that will improve their input accuracy and shorten the time to perform data entry in the field. The new Mobility solution will also provide supervisors better visibility into where the crews are working, what work they have completed and how that work breaks down to capital, maintenance, and retirement. Contractors will be able to use the new Mobility solution on any device to send data back to Con Edison without the need for back office data entry or expensive interfaces. The Mobility module will allow Con Edison representatives to approve the Contractor work for payment.

- Non-financial Benefits:
  Streamlines and improves work-flows and processes.

- Summary of Financial Benefits (if applicable) and Costs:
  The WMS Upgrade and Mobile Replacement is a one-time cost to upgrade to that latest version of the CGI Asset Resource Management (ARM) Suite of products. We will also be retiring the Field Manager product that is used by the Field Crews. We expect to see annual savings by the field crews, field supervisors, clerks and engineers based on streamlined data entry within ARM and the new Mobile solution. We also expect to eliminate 13 contractor personnel that perform data entry for the contractor inspection crews by providing those crews with a mobile solution.
  There are expected productivity improvements based on streamlined data entry for required data for 1000 field crews and 350 field supervisors. This will allow for more productive time in the field. We expect the following savings due to more work being accomplished within the shift:
  - Capital $1.7M
  - Retirement $693K
  - O&M $1.3M

  There are approximately 13 contractor personnel supporting data entry for field contractors. The new mobile solution will have a contractor module that will eliminate the need for these back office personnel and creating an annual savings of $345k of O&M Annually.

  In addition, Distribution Engineering incurs $181k annually in O&M for IT support of custom application used by the Stray Voltage Contractors to collect data on Stray Voltage testing. This data collection will become part of the contractor module of the new Mobile solution eliminating the $181k annual O&M Cost.

  The upgrade to the latest version of the CGI ARM Suite of products (WMS Upgrade) will allow for streamlined data entry for the 75 Clerks and Engineers creating the Work Requests for field crews. This will allow for more productive time in the office. We expect the following savings due to more work being accomplished within the shift:
  - Capital $9.8K
  - O&M $4K

- Technical Evaluation/Analysis:

- Project Relationships (if applicable):
  Oracle BI, STAR Outage Management System, Oracle Project Accounting, Oracle Labor Distribution, the Energy Services (CPMS) Pega application, HR Payroll PeopleSoft, LayOut Tracking (LOTs) system and PowerPlant

- Basis for Estimate:
  The estimate for this project is based on cost of the new hardware and software as well as the historical cost of integrating a software package of this scope and magnitude.

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		1,595
M&S	-	-	-	-		423
A/P	-	-	-	1,020		4,204
Other	-	-	-	-		2,721
Overheads	-	-	-	15		857
Total	-	-	-	**1,035**		**9,800**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	4,886	1,315	-	-	-
M&S	-	-	-	-	-
A/P	2,220	4,816	-	-	-
Other	534	428	-	-	-
Overheads	2,359	681	-	-	-
Total	**10,000**	**7,240**	-	-	-

Schedule 4:

T&D O&M White Papers

Information Technology

	Capital
X	O&M

2019 – Central Operations/ System & Transmission Operations

Project/Program Title	Outage Scheduling System- Maintenance and Production Support
Hyperion Project Number	N/A
Status of Project	In Production
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:
The Outage Scheduling System (OSS) is used to submit, review and approve outage requests on the electric system.

The current OSS was implemented during 2016 and 2017 on a web based Pega platform. The Pega licensing model allows up to an agreed number of cases to be created or re-opened per year.

There are annual license costs associated with the Pega software and with the IBM webshare servers that host the application and database.

Minimum levels of typical maintenance and production support activities include:

- Microsoft patch testing
- Generating license compliance statistics
- Server, application and database maintenance
- Defect fixes
- Response to production down or system wide blocker issues (24x7)
- Implement required software changes prompted by immediate business needs
- Automated regression testing on all code moved to Production
- Code migrations

These activities require: 150% Full Time Equivalent (FTE) developer support, 50%FTE Pega Technical Architect and 50% FTE Quality Assurance Support.

Justification Summary:
OSS is essential for supporting the reliability, safety and outage notification compliance requirements for Con Edison's electric transmission, subtransmission and distribution systems. It is utilized by Electric Operations, Substations Operations, System and Transmission Operations and Steam Operations and indirectly by the generating units in the Company territory as well as all neighboring transmission owners to plan, coordinate and finalize for implementation all equipment outages (capital, retirement, compliance, O&M) needed to inspect, repair and upgrade the electric system components.

If OSS stops functioning all outage scheduling work would have to be performed manually. Given the volume it is not feasible to schedule all necessary outages and make all appropriate notifications using manual processes. This will lead to a) conflicts in scheduled work; b) missed opportunities for outages; both a) and b) will negatively impact system reliability and the safety of personnel; and c) non-compliance with New York Independent System Operator (NYISO), North American Electric Reliability Corporation (NERC) and the NY State Public Service Commission (PSC) notification requirements.

Supplemental Information:

- Alternatives: No support for OSS
- Risk of No Action: Accumulating exception logs and production errors that cause the application to stall; security issues causing the application to become isolated from the corporate network in order to minimize security risk to the network; loss of application.
- Non-financial Benefits: Not applicable
- Summary of Financial Benefits (if applicable) and Costs: Not applicable
- Technical Evaluation/Analysis: Not applicable
- Project Relationships (if applicable): Not applicable
- Basis for Estimate: Estimates are based on current and projected production support and maintenance costs

Total Funding Level ($000):

Historical Elements of Expense

(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-	-	-
M&S	-	-	-	-	-	-
A/P	-	-	-	-	**242**	**435**
Other	-	-	-	-	-	-
Total	-	-	-	-	**242**	**435**

Request by Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	-	-
M&S	-	-	-	-	-
A/P	479	479	479	479	479
Other	-	-	-	-	-
Overheads	-	-	-	-	-
Total	**479**	**479**	**479**	**479**	**479**

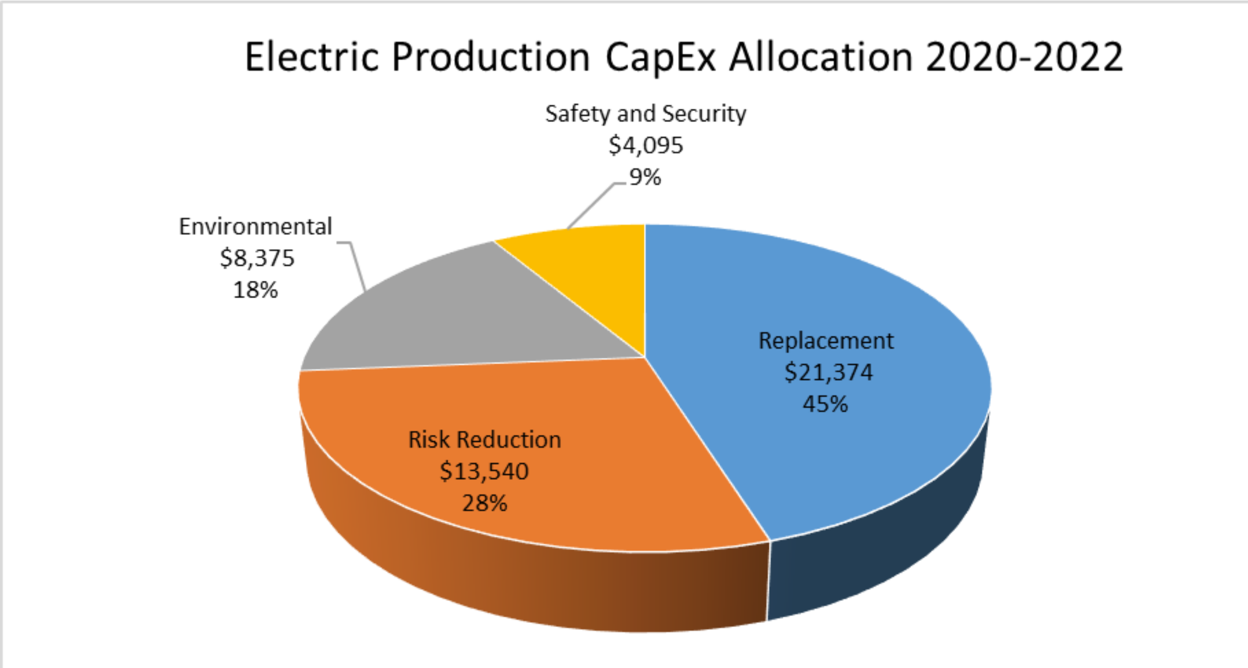
Exhibit__(EIOP-11)

Electric Production

Schedule 1: EP Capital Program and Project Summary

Electric Production		Year Total			
		Current Budget			
		Total Dollars ($000)			
		RY1	RY2	RY3	3 Yr. Total
Organization	**White Paper**				
	REPLACEMENT				
Electric Production	Boiler 70 Super-heater Elements	-	6,500	-	6,500
Electric Production	Boiler 70 Re-heater Elements	504	3,250	-	3,754
Electric Production	Boiler 70 Rear Wall Hopper Slope	-	3,250	-	3,250
Electric Production	Boiler 70 Rear Wall BRILC	-	2,000	-	2,000
Electric Production	Replace 6CP Unit Substation	-	1,000	1,500	2,500
Electric Production	ER 71 Circulator Switchgear Replacement	-	220	-	220
Electric Production	ER 72 Circulator Switchgear Replacement	-	220	-	220
Electric Production	73 Boiler Feed Pump Substation Replacement	-	500	500	1,000
Electric Production	60-FDE Unit Substation Replacement	-	-	500	500
Electric Production	60-FDW Unit Substation Replacement	-	-	500	500
Electric Production	Battery Replacements	-	30	-	30
Electric Production	Roof Replacement Over Unit 6/60 Fans	-	675	-	675
Electric Production	Replace Control Room HVAC	-	225	-	225
	Replacement Subtotal	504	17,870	3,000	21,374
	RISK REDUCTION				
Electric Production	Boiler 60 Chemical Clean Modifications	-	-	2,070	2,070
Electric Production	Replace the Unit 7/70 Circulating Water Pumps	-	-	500	500
Electric Production	Purchase Spare Traveling Screen	-	800	-	800
Electric Production	Replace Traveling Screens 4 & 5	-	-	1,500	1,500
Electric Production	Traveling Screen No. 8 Overhaul	-	-	650	650
Electric Production	TR-7E Replacement	7,000	-	-	7,000
Electric Production	East River Units 60 and 70 O_2 Trim	-	459	-	459
Electric Production	Replace Legacy Control Systems	300	-	-	300
Electric Production	Replace Steam Pressure Control Valve	-	141	-	141
Electric Production	Replace GT1 GE Relays	-	-	120	120
	Risk Reduction Subtotal	**7,300**	**1,400**	**4,840**	**13,540**
	ENVIRONMENTAL				
Electric Production	No. 2 oil conversion	-	750	6,500	1,500
Electric Production	Replace Dock Transformer	-	1,000	-	1,000
Electric Production	Cable Cooling Dielectric Leak Detection	-	125	-	125
	Environmental Subtotal	-	1,875	6,500	8,375
	SAFETY AND SECURITY				
Electric Production	Fire Alarm System in Unit 6/7 Plant Areas	1,500	-	-	1,500
Electric Production	Install Access Platforms	1,295	-	-	1,295
Electric Production	Update ER Emergency Evacuation System	-	500	-	500
Electric Production	Repair Slabs Under Transfer House	-	250	-	250
Electric Production	Lube Oil Room Ventilation	-	-	550	550
	Safety and Security Subtotal	2,795	750	550	4,095
	Total - Electric Production	**10,599**	**21,895**	**14,890**	**47,384**

Schedule 2: EP Capital Allocation Categories



Schedule 3:

EP Capital White Papers

Replacement

X	Capital
	O&M

2019 – Steam Production / Electric Production

Project/Program Title	Boiler 70 Super-heater Elements
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22138128
Status of Project	Planning
Estimated Start Date	January 2019
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will replace one hundred thirty six (136) convection super-heater 2.5" outside diameter (OD) elements, the super-heater inlet header, and two (2) intermediate super-heater headers on East River Boiler 70. The super-heater supports and alignment attachments will be redesigned and reinstalled. In addition, casing and refractory will be installed. This project requires an outage.

Justification Summary:
The replacement of the convection super-heater elements is necessary for the reliable operation of East River Boiler 70. Over the years, the majority of the support structure for the super-heater has developed stress fractures which have led to tube misalignment and sagging. As a result of the excessive material stresses on surrounding attachments, elements become detached and collapsed. There is significant separation from the rear wall caused by the sagging. Because of the separation and sagging, as well as the refractory damage, bypass paths for the combustion gases have developed. This adds stress to the tubing, supports and headers, and adversely affects efficiency.

Supplemental Information:

- Alternatives:
  An alternative would be to repair super-heater tube failures as they occur and continue to attempt "in field" fixes to further support and align the super-heater. Attempts at in situ support corrections have been proven unsuccessful, and future attempts are not recommended.

- Risk of No Action:
  Based on the current super-heater condition, not completing this project will increase the risk of forced outages and reduce the availability of East River Unit 7/70.

- Non-financial Benefits:
  This project will help to maintain the reliability and availability of East River Unit 7/70 and prevent super-heater outage work.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Condition assessments outlined in the inspection reports highlight the failure patterns and the past attempts at supporting and aligning the super-heater elements which have been unsuccessful. East River Boiler 70 requires a new super-heater, as well as a redesign of the super-heater support and alignment structures, as the super-heater elements have sagged and deformed. Attempting to upgrade the support structures without replacing the elements would lead to increased internal stresses within the tubing and risk further outages caused by cracking of the stressed tubes.

- Project Relationships (if applicable):
  This project will be completed in tandem with 70 Re-heater – East River Station, which will address a similar support attachment failure mechanism within the upper re-heater.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	0	-	120	-	-
M&S	798	-	135	-	-
A/P	0	-	4,650	-	-
Other	0	-	24	-	-
Overheads	202	-	1,571	-	-
Total	**1,000**	**-**	**6,500**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Boiler 70 Re-heater Elements
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.21485875
Status of Project	Planning
Estimated Start Date	January 2019
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will replace the East River Boiler 70 re-heater elements. The re-heater section consists of three (3) banks, each with one hundred eighty two (182) rows of 2" diameter tubing, which are known as the elements. In addition, new re-heater support attachments, casing and refractory will be installed. As part of this work, gas seals around the main re-heat and re-heat bypass sections will be enhanced by redesigning the refractory and brick supports, as well as the convection rear wall/re-heat wall corner seals. This project requires an outage.

Justification Summary:
The replacement of the upper re-heater elements is necessary for the reliable operation of East River Boiler 70. Over the years, the majority of the re-heater support structure has developed stress fractures which have led to tube misalignment and sagging. As a result of these excessive material stresses on surrounding attachments, elements become detached and collapsed. The same stresses have resulted in five (5) pinhole leaks along the 6 o'clock position at the edge of a re-heater support saddle. There is also separation from the rear wall causing re-heater tube sags that affect efficiency and add stress to the headers. The wall separation, along with refractory damage, created bypass paths for the combustion gases that are only accessible with the re-heater removed. The boiler efficiency has suffered as a result of these unintended changes in gas flow paths, including hot gas leakage from the main re-heat to the re-heat bypass sections.
The original design of the boiler included a re-heater support structure that the manufacturer determined to be inadequate and precluded in their subsequent designs. The support structures have to be redesigned and reinstalled to prevent future failures.

Supplemental Information:

- Alternatives:
  One alternative is to repair re-heater tube failures as they occur. This option is not recommended because it potentially exposes the steam system to forced outages and reduces the unit's availability.

- Risk of No Action:

Not implementing this project will increase the risk of forced outages and reduce the availability of East River Unit 7/70.

- Non-financial Benefits:
  This project will help to maintain the availability of East River Unit 7/70 and prevent re-heater outage work.

- Summary of Financial Benefits (if applicable) and Costs:
  The portion of the project that addresses the sealing of the re-heat bypass section will result in efficiency improvements, increased turbine output and fuel savings.

- Technical Evaluation/Analysis:
  Condition assessments outlined in the inspection reports highlight the failure patterns and the past attempts to support the elements which have been unsuccessful. East River Boiler 70 requires a new re-heater, as well as redesigned re-heater support structures, because the re-heater is experiencing sagging tubes. Attempting to upgrade the support structures without replacing the elements would lead to increased internal stresses within the tubing, and risk further outages caused by cracking of the stressed tubes.

- Project Relationships (if applicable):
  This project will be completed in tandem with 70 Super-heater Replacement – East River Station, which will address a similar support attachment failure mechanism within the convective super-heater.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	180	-	-
M&S	399	383	-	-	-
A/P	-	-	2,222	-	-
Other	-	-	21	-	-
Overheads	101	121	827	-	-

Total	**500**	**504**	**3,250**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Boiler 70 Rear Wall Hopper Slope
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.2EP4500
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will replace one hundred eighty three (183) boiler tubes (3-inch tube diameter) in the Rear Furnace Wall Hopper Slope of East River Boiler 70. The tubes have deteriorated and are susceptible to metal fatigue. This tube replacement project will require the removal and installation of assorted attachments, supports, brick, refractory, insulation, lagging, and casing (BRILC). This project requires an outage.

Justification Summary:
The East River Boiler 70 Rear Furnace Wall Hopper Slope tubes are located adjacent to the rear radiant furnace wall. The boiler tubes in this area are degraded from long term corrosion. The tubes have pitting and are susceptible to metal fatigue. This project will replace the tubes and restore the integrity of this section of the boiler.

Supplemental Information:

- Alternatives:
  One alternative is to repair Rear Furnace Wall Hopper Slope tube failures as they occur. This is not recommended because it potentially exposes the boiler system to forced outages, reducing the unit availability and reliability.

  A second alternative is to selectively replace tubes in damaged areas. Partial tube replacements are not recommended as the tubes in this section of the boiler would continue to deteriorate over time, causing unit forced outages.

- Risk of No Action:
  Not implementing this project exposes the steam and electric system to forced outages and the loss of electric and steam production.

- Non-financial Benefits:
  This project will increase the reliability of East River Boiler 70.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	160	-	-
M&S	-	-	271	-	-
A/P	-	-	1,779	-	-
Other	-	-	220	-	-
Overheads	-	-	820	-	-
Total	**0**	**0**	**3,250**	**0**	**0**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Boiler 70 Rear Wall BRILC
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22100413
Status of Project	Planning
Estimated Start Date	January 2019
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will remove and replace the bricks/tiles, refractory, insulation, lagging, and casing (BRILC) from the rear waterwall of East River Boiler 70. This will allow for cleaning the tube surfaces from elevation 58'-10" to elevation 93'-0" in order to establish the insulating integrity of the rear walls and help maintain the sliding interface which is integral to the boiler design. The project will also seal gaps between tubes by pulling deformed tubes into place, troweling castable insulation between tubes to minimize the leak path of tramp air, replacing/installing observation and access doors, and sealing the northeast and northwest corners to mitigate furnace flue gas by-pass.

Justification Summary:
The internal sliding interface has been problematic, leading to the deterioration of the boiler refractory and insulation. The deterioration of the brick work and insulation has been exacerbated by bowing of the waterwall tubes allowing hot flue gases to enter the BRILC area causing it to deteriorate and fail. During an external thermograph inspection of the rear waterwall casing in October 2013, various hot spots were identified with some locations exceeding 900°F. These hot spots were an indication of BRILC failure.

Supplemental Information:

- Alternatives:
  An alternative is to plug tubes as needed and perform partial repairs as required. This alternative is not recommended because plugging tubes may lead to irrevocable damage due to uneven distribution of heat in the boiler.

- Risk of No Action:
  Not implementing this project could result in unplanned outages of Boiler 70, making it difficult to maintain steam send-out to customers.

- Non-financial Benefits:
  By replacing the tubing, the boiler can be operated as designed. After restoration, the boiler will also have a much higher availability allowing the system to operate with the reliability necessary to effectively supply steam to New York City customers.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  This project is not directly associated with any other project, however there is a possibility of optimizing material purchases for similar units.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	0	-	145	-	-
M&S	279	-	225	-	-
A/P	0	-	1,100	-	-
Other	0	-	9	-	-
Overheads	71	-	521	-	-
Total	**350**	**-**	**2,000**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Replace 6CP Unit Substation
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.6EP9712
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2022
Work Plan Category	Strategic

Work Description:
This project will replace unit substation 6CP with a new and more reliable unit substation and upgrade the 61 & 62 Circulator Motor Operated Valve (MOV) Controls at East River Unit 6/60. This project will also transfer the loads from unit substation 5CP to the new 6CP, and permanently remove unit substation 5CP. A new enhanced 13.8kV protection and isolation breaker and a new combination disconnect and ground switch will be installed as part of the new 6CP unit substation. This project will provide enhanced protection features by installing new microprocessor based protective relays. The new unit substation will be integrated into the East River Unit 6/60 Ovation Distributed Control System (DCS).

Justification Summary:
Unit substations 5CP and 6CP were originally installed in the mid 1950s. Due to their vintage, spare parts are difficult to obtain. Moreover, the equipment is no longer supported by the original manufacturer, making equipment maintenance no longer cost-effective (e.g. the switchgear breaker compartment racking mechanisms are in need of maintenance and need to be sent to a third party for overhaul). In 2007, the unit substation 5CP transformer failed beyond repair. Due to this equipment failure, the switchgear for 5CP is currently powered from unit substation 6CP. The 5CP transformer has since been disconnected and retired in place. Merging the loads of 5CP into the new 6CP will eliminate the need to replace unit substation 5CP. This consolidation of equipment will reduce overall maintenance.
Additionally, the 6CP transformer is currently leaking nitrogen and requires maintenance in order to maintain pressure. A transformer of this vintage could also contain trace amounts of PCB's from corrosion inhibiting coatings used in the past. Furthermore, remote control, metering and monitoring capabilities are not available for the existing equipment. The new circulating water pump control panels will provide real-time data about the pumps to the operators in the control room to monitor the circulating water pumps. This data will assist in troubleshooting any pump issues that may arise. The new 13.8kV circuit breaker and combination disconnect and ground switches will allow for a safer and quicker isolation of the 6CP unit substation from the 13.8kV feeder during maintenance and outage activities.

Supplemental Information:

- Alternatives:
  An alternative is to replace both unit substations 5CP and 6CP with new equipment, including isolation at the 13.8kV distribution level. This option is not recommended because it would require a larger footprint, which is not available due to space limitations.

- Risk of No Action:
  Not implementing this project could result in a transformer failure for 6CP, causing the loss of power to the circulating water pumps, and could result in a trip of East River Unit 6/60. A forced outage of East River Unit 6/60 will cause the loss of steam and electric production.

- Non-financial Benefits:
  This project is operationally driven to improve the reliability of East River Unit 6/60. It will reduce the maintenance activities and enhance personnel safety.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  This project is related to 71 Circulator Switchgear Replacement and 72 Circulator Switchgear Replacement.

- Basis for Estimate:
  The funding for this project was determined using a Partial Appropriation Estimate.

Annual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	0	500	-
M&S	-	-	765	150	-
A/P	-	-	0	200	-
Other	-	-	0	131	-
Overheads	-	-	235	519	-
Total	**-**	**-**	**1,000**	**1,500**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	ER 71 Circulator Switchgear Replacement
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22093385
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2023
Work Plan Category	Strategic

Work Description:
This project will retrofit the switchgear in unit substation CIRC 71-7 with new and more reliable components, at East River Unit 7/70. This project will provide enhanced protection features by installing new microprocessor based protective relays. The new equipment will be integrated into the East River Unit 7/70 Ovation Distributed Control System (DCS).

Justification Summary:
Presently the switchgear of unit substation CIRC 71-7 has deteriorated and become difficult to operate. The switchgear was installed in the 1950s and replacement parts are difficult to obtain. The equipment is no longer supported by the original manufacturer, thus maintenance is becoming increasingly difficult to perform (e.g. the switchgear breaker compartment racking mechanisms need to be sent to a third party for overhaul). Unit substation CIRC 71-7 provides power to Circulating Water Pump No. 71. A failure or loss of power from this unit substation will cause a loss of electric production from East River Unit 7/70.

Supplemental Information:

- Alternatives:
  One alternative to this project is to replace the entire unit substation with new equipment and provide a fixed 13.8kV circuit breaker and combination disconnect and grounding switch. This alternative is not feasible due to space limitations, because the footprint of the new equipment would exceed the space available.

- Risk of No Action:
  Not implementing this project may decrease the availability (electric production) of East River Unit 7/70. A failure or loss of power from the unit substation to the circulating water pump motor will cause East River Unit 7/70 to be derated.

- Non-financial Benefits:
  This project will help to maintain the availability of East River Unit 7/70.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Due to space constraints, this project is contingent upon the completetion of Replace 6CP Unit Substation - ER 60, and it is related to 72 Circulator Switchgear Replacement.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	0	-	120
M&S	-	-	168	-	500
A/P	-	-	0	-	75
Other	-	-	0	-	28
Overheads	-	-	52	-	277
Total	**-**	**-**	**220**	**-**	**1,000**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	ER 72 Circulator Switchgear Replacement
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.7EP9811
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2023
Work Plan Category	Strategic

Work Description:
This project will retrofit the switchgear in the unit substation CIRC 72-7 with new and more reliable components, at East River Unit 7/70. This project will provide enhanced protection features by installing new microprocessor based protective relays. The new equipment will be integrated into the East River Unit 7/70 Ovation Distributed Control System (DCS).

Justification Summary:
Presently the switchgear of unit substation CIRC 72-7 has deteriorated and become difficult to operate. The switchgear was installed in the 1950s and replacement parts are difficult to obtain. The equipment is no longer supported by the original manufacturer, thus maintenance is becoming increasingly difficult to perform (e.g. the switchgear breaker compartment racking mechanisms need to be sent to a third party for overhaul). Unit substation CIRC 72-7 provides power to Circulating Water Pump No. 72. A failure or loss of power from this unit substation will cause a loss of electric production from East River Unit 7/70.

Supplemental Information:

- Alternatives:
  One alternative to this project is to replace the entire unit substation with new equipment and provide a fixed 13.8kV circuit breaker and combination disconnect and grounding switch. This alternative is not feasible due to space limitations, because the footprint of the new equipment would exceed the space available.

- Risk of No Action:
  Not implementing this project may decrease the availability (electric production) of East River Unit 7/70. A failure or loss of power from the unit substation to the circulating water pump motor will cause East River Unit 7/70 to be derated.

- Non-financial Benefits:
  This project will help to maintain the availability of East River Unit 7/70.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Due to space constraints, this project is contingent upon the completion of Replace 6CP Unit Substation - ER 60, and it is related to 71 Circulator Switchgear Replacement.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	0	-	120
M&S	-	-	168	-	500
A/P	-	-	0	-	75
Other	-	-	0	-	28
Overheads	-	-	51	-	277
Total	**-**	**-**	**220**	**-**	**1,000**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	73 Boiler Feed Pump Substation Replacement
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.6EP0107
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2023
Work Plan Category	Strategic

Work Description:
This project will retrofit the switchgear in unit substation BF-73 with new and more reliable components, at East River Unit 7/70. This project will provide enhanced protection features by installing new microprocessor based protective relays. The new equipment will be integrated into the East River Unit 7/70 Ovation Distributed Control System (DCS).

Justification Summary:
Presently, the switchgear of unit substation BF-73 has deteriorated and become difficult to operate. The switchgear is antiquated and replacement parts are difficult to obtain. The equipment is no longer supported by the original manufacturer, thus maintenance is becoming increasingly difficult to perform (e.g. the switchgear breaker compartment racking mechanisms need to be sent to a third party for overhaul). Unit substation BF-73 provides power to Boiler Feed Pump No. 73. A failure or loss of power from this unit substation will cause a derate of electric production from East River Unit 7/70.

Supplemental Information:

- Alternatives:
  One alternative is to replace the entire unit substation with new equipment and provide a fixed 13.8kV circuit breaker and combination disconnect and grounding switch for isolation. This option is not feasible due to space limitations. The footprint of the new equipment would exceed the space available.

- Risk of No Action:
  Not implementing this project will have an impact on the reliability (electric production) of East River Unit 7/70. A failure or loss of power from the unit substation will cause East River Unit 7/70 to be derated.

- Non-financial Benefits:
  This project will improve the reliability of East River Unit 7/70.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	60	60	150
M&S	-	-	250	250	150
A/P	-	-	37	38	1,100
Other	-	-	14	14	153
Overheads	-	-	137	136	547
Total	**-**	**-**	**500**	**500**	**2,100**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	60-FDE Unit Substation Replacement
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22138121
Status of Project	Planning
Estimated Start Date	January 2022
Estimated Completion Date	December 2023
Work Plan Category	Strategic

Work Description:
This project will replace the existing Forced Draft (FD) Fan East unit substation 60-FDE with a new more reliable unit substation at East River Unit 6/60. A new enhanced 13.8kV protection and isolation breaker and a new combination disconnect and ground switch will be installed as part of the new 60-FDE unit substation. This project will provide enhanced protection features by installing new microprocessor based protective relays. The new unit substation will be integrated into the East River Unit 6/60 Ovation Distributed Control System (DCS).

Justification Summary:
Unit substation 60-FDE was originally installed in the mid 1950s. Presently, the unit substation and associated equipment are in poor condition. The switchgear is outdated and replacement parts are difficult to obtain. The switchgear circuit breakers are difficult to operate and require maintenance to put into operation. This equipment is no longer supported by the original manufacturer, thus maintenance is becoming increasingly difficult to perform (e.g. the switchgear breaker compartment racking mechanisms need to be sent to a third party for overhaul).
The transformer of the unit substation is a nitrogen pressurized, dry-type transformer. Currently, it is not holding nitrogen pressure and requires maintenance in order to maintain pressure. A transformer of this vintage could also contain trace amounts of PCBs from corrosion inhibiting coatings used in the past.
The new 13.8kV circuit breaker and combination disconnect and ground switch will allow for a safer and quicker isolation of the 60-FDE unit substation from the 13.8kV feeder during maintenance and outage activities.

Supplemental Information:

- Alternatives:
  An alternative is to operate and maintain the equipment in its present state. This option is not recommended because of the increased maintenance of the breaker compartment racking mechanisms, breaker charging motors, cell switches and other auxiliary switches. The spare parts for this equipment are increasingly difficult to obtain. The addition of a circuit breaker and a combination isolation and grounding switch will expedite maintenance work and enhance personnel safety.

- Risk of No Action:
  Not implementing this project will have an impact on the reliability (electric production) of East River Unit 6/60. A failure or loss of power from the unit substation to the FD fan motor will cause a trip of Boiler 60.

- Non-financial Benefits:
  This project will improve the availability of East River Unit 6/60.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  This project is related to 60 FDW Unit Substation Replacement – ER 60.

- Basis for Estimate:
  The funding for this project was determined using an Order of Magnitude Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	0	1,250
M&S	-	-	-	385	450
A/P	-	-	-	0	900
Other	-	-	-	0	144
Overheads	-	-	-	115	1,406
Total	**-**	**-**	**-**	**500**	**4,150**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	60-FDW Unit Substation Replacement
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.7EP9827
Status of Project	Planning
Estimated Start Date	January 2022
Estimated Completion Date	December 2023
Work Plan Category	Strategic

Work Description:
This project will replace the existing Forced Draft (FD) Fan West unit substation 60-FDW with a new more reliable unit substation at East River Unit 6/60. A new enhanced 13.8kV protection and isolation breaker and a new combination disconnect and ground switch will be installed as part of the new 60-FDW unit substation. This project will provide enhanced protection features by installing new microprocessor based protective relays. The new unit substation will be integrated into the East River Unit 6/60 Ovation Distributed Control System (DCS).

Justification Summary:
Unit substation 60-FDW was originally installed in the mid 1950s. Presently, the unit substation and associated equipment are in poor condition. The switchgear is outdated and replacement parts are difficult to obtain. The switchgear circuit breakers are difficult to operate and require maintenance to put into operation. This equipment is no longer supported by the original manufacturer, thus maintenance is becoming increasingly difficult to perform (e.g. the switchgear breaker compartment racking mechanisms need to be sent to a third party for overhaul).
The transformer of the unit substation is a nitrogen pressurized, dry-type transformer. Currently, it is not holding nitrogen pressure and requires maintenance in order to maintain pressure. A transformer of this vintage could also contain trace amounts of PCB's from corrosion inhibiting coatings used in the past.
The new 13.8kV circuit breaker and combination disconnect and ground switch will allow for a safer and quicker isolation of the 60-FDW unit substation from the 13.8kV feeder during maintenance and outage activities.

Supplemental Information:

- Alternatives:
  An alternative is to operate and maintain the equipment in its present state. This option is not recommended because of the frequent maintenance of the switchgear breakers and the leaking transformer.

- Risk of No Action:
  Not implementing this project could result in a 60-FDW transformer failure, causing the loss of power to the FD fan motor, resulting in a trip of Boiler 60.

- Non-financial Benefits:
  This project will improve the availability of East River Unit 6/60.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  This project is related to 60 FDE Unit Substation Replacement – ER 60.

- Basis for Estimate:
  The funding for this project was determined using an Order of Magnitude Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	0	1250
M&S	-	-	-	385	450
A/P	-	-	-	0	900
Other	-	-	-	0	144
Overheads	-	-	-	115	1,408
Total	**-**	**-**	**-**	**500**	**4,150**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Battery Replacements
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22636940
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will replace the existing Uninterruptible Power Supply (UPS) batteries and Station batteries installed at East River Units 6/60 and 7/70 based on the battery replacement specification requirements. The batteries which are part of the UPS system and the station's DC power supply system will be replaced with like in kind.

Justification Summary:
The battery banks are the source for vital station loads in the event of a loss of normal power supply at the station. The ability to supply an emergency source of power during the loss of AC or DC power supplies is essential to prevent trips of East River Units 6/60 and 7/70. Given the criticality of the battery banks to prevent unit trips, the battery banks should be capable of functioning at rated capacity at all times. Given the time in service and material condition of the battery banks associated with East River Units 6/60 and 7/70, in accordance with the battery replacement specification, they cannot be relied upon to provide an emergency source of power for the units. The battery banks must be replaced to maintain the overall reliability of East River Units 6/60 and 7/70.

Supplemental Information:

- Alternatives:
  An alternative is to install one (1) large bank of batteries to be shared between all station critical loads. This alternative is not recommended because it would decrease the reliability of both East River Units 6/60 and 7/70 in the event of a battery or battery circuit failure. It would also defeat the purpose of unitization.

- Risk of No Action:
  These battery banks act as a backup power supply to AC and DC critical panel boards. A failure of the batteries upon a loss of the normal power supply to these critical AC and DC loads can cause a unit trip.

- Non-financial Benefits:
  Maintaining the battery life will provide proper performance, reliability, and safe operation of the equipment.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	0	-	-
M&S	-	-	23	-	-
A/P	-	-	0	-	-
Other	-	-	0	-	-
Overheads	-	-	7	-	-
Total	**-**	**-**	**30**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Roof Replacement Over Unit 6/60 Fans
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22648665
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will replace the roofing membrane and walking surfaces on the roof over the East River Unit 6/60 fans. The membrane was found to have several rips and tears as well as some debonding between the membrane and the concrete roof slab.

Justification Summary:
Existing rips and tears of the roof membrane are causing building leaks in the vicinity of the East River Unit 6/60 fans; not only putting the fans at risk, but also, in the long term causing premature deterioration of building structural elements. The condition of the roofing system, will continue to degrade if not replaced, further jeopardizing plant equipment and structures.
Stack monitors, trailers, and other equipment are located on this roof and require constant access by plant personnel. The debonded membrane presents a hazardous walking surface for employees that must cross the roof to access equipment. Rubber pavers will be installed to protect the roofing membrane from inadvertant damage and to provide a safe walking path for employees.

Supplemental Information:

- Alternatives:
  One alternative to this project is to install insulated steel panels over the existing roofing membrane. This alternative is not recommended because it is more expensive than installing a new roofing membrane system.

- Risk of No Action:
  If the roofing membrane is not replaced and deterioration continues to progress, structural components will be damaged, equipment will remain at risk of damage, and employees will continue to be exposed to a safety hazard.

- Non-financial Benefits:
  Employee safety will be improved immediately through the installation of a new roofing membrane system.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  The condition of the roof was determined to be poor by several independent inspections, including manufacturer inspections and engineering inspections.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Order of Magnitude Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	25	-	-
M&S	-	-	30	-	-
A/P	-	-	450	-	-
Other	-	-	2	-	-
Overheads	-	-	168	-	-
Total	**-**	**-**	**675**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Replace Control Room HVAC
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.3EP2302
Status of Project	In-Progress
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will replace the existing roof mounted heating, ventilating, and air-conditioning (HVAC) unit for the former East River Units 6/60 and 7/70 Control Room. This room has been re-utilized as an office and training simulation area for station personnel. A new rooftop HVAC unit will be installed along with a standard electric heater and air side economizer. Associated roof, ductwork and electrical supply feed modifications will also be performed as part of the project. The new HVAC unit will be regulated by a control panel and serve the new office/training simulation area, existing locker room, and existing shift supervisor's office.

Justification Summary:
The existing HVAC unit is well beyond the expected service life and has broken down several times in the last few years, despite having been serviced several times to keep the unit running. An effective and energy efficient HVAC system is necessary to protect the electronic equipment within this room and maintain acceptable indoor air conditions.

Supplemental Information:

- Alternatives:
  One alternative to this project is to relocate the East River Units 6/60 and 7/70 Control Room and associated equipment. This is not recommended because it would be cost prohibitive.

  A second alternative to this project is to continue operating with the existing conditions. This is not recommended because it could lead to electronic equipment failures caused by overheating if the HVAC unit continues to break down.

- Risk of No Action:
  The unit may continue to break down during the summer months and the resulting heat could affect the sensitive electronics in the Control Room. In addition, the elevated temperatures would subject station personnel to an extremely uncomfortable environment.

- Non-financial Benefits:
  This project will help to protect the existing electronic equipment still kept within the former East River Units 6/60 and 7/70 Control Room, as well as maintain acceptable indoor air conditions for personnel.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  This project is already in-progress. Future projections are based on an Appropriation Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	77	7	-	-	-	-
M&S	29	-	13	-	-	-
A/P	77	4	21	39	-	-
Other	-	-	3	-	-	-
Overheads	124	10	11	10	-	-
Total	**307**	**21**	**48**	**49**	**-**	**0**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	16	-	-
M&S	-	-	0	-	-
A/P	-	-	150.5	-	-
Other	-	-	0	-	-
Overheads	-	-	58.5	-	-
Total	**-**	**-**	**225**	**-**	**-**

Schedule 4:

EP Capital White Papers

Risk Reduction

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Boiler 60 Chemical Clean Modifications
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.20989610
Status of Project	Planning
Estimated Start Date	January 2022
Estimated Completion Date	December 2023
Work Plan Category	Operationally Required

Work Description:
This project will upgrade the chemical cleaning system for East River Boiler 60. The frequency of chemical cleaning is determined from analyzing deposits on tube samples. The new chemical clean system will utilize forced circulation to evenly distribute cleaning chemicals from the lower headers of the boiler to the steam drum during a chemical cleaning. The flow through each section of the boiler will be regulated to allow adequate resident time in the tubes to effectively remove deposits. The Company is switching from hydrochloric acid to ethylenediaminetetraacetic acid (EDTA) to clean the boiler tubes because it is environmentally friendly. The existing small diameter chemical piping system configuration is undersized for external circulation and chemical cleaning using EDTA, so larger diameter piping will be installed. The boiler was last chemically cleaned in 2011 using EDTA with limited success because of the inability to effectively circulate chemicals through the system. This project requires a unit outage.

Justification Summary:
The existing chemical clean connections were originally designed for hydrochloric acid, which uses a fill and soak method. The use of hydrochloric acid for chemical cleaning has stopped due to environmental reasons. The EDTA chemical needs to be heated and circulated through the boiler to perform a chemical clean. If the EDTA is unevenly distributed through the boiler, which was confirmed during several past chemical cleanings by chemical samples taken from the drum and lower waterwall headers, then the cleaning is potentially ineffective. Tube samples taken from the South, East, and West waterwalls after the 2011 chemical cleaning had significantly lower deposit content than the North waterwall. The existing system needs to be enlarged and expanded so chemicals are circulated evenly throughout the boiler. This project will enlarge and expand the existing chemical cleaning system so that the EDTA chemicals are circulated throughout the boiler to provide an effective chemical clean.

Supplemental Information:

- Alternatives:
  An alternative would be to continue chemical cleaning with the uneven distribution of EDTA. This alternative would result in more frequent boiler chemical cleanings, or premature replacement of select boiler sections, and is therefore not recommended.

A second alternative would be to run temporary hoses throughout the station for the boiler chemical cleaning. This is not recommended as hot, pressurized chemicals would be flowing thru the hoses during the cleaning and could be a safety hazard if a hose were to leak or fail.

- Risk of No Action:
  Not implementing this project will result in more frequent boiler chemical cleanings and the boiler areas which are difficult to reach with EDTA could be subject to tube failures.

- Non-financial Benefits:
  An effective chemical cleaning of the boiler will help to maintain boiler performance, availability and reliability.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  The tube sample analysis from prior chemical cleanings revealed uneven boiler cleaning caused by inadequate piping to recirculate the boiler chemicals. This project will increase the capacity of the chemical clean piping.

- Project Relationships (if applicable):
  A similar project scope to chemically clean Boiler 70 by forced circulation was completed in 2015. The new Boiler 60 chemical cleaning system will tie into a section of the Boiler 70 chemical cleaning system to make a common connection to the vendor's equipment.

- Basis for Estimate:
  The funding for this project was determined using an Order of Magnitude Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	300	150
M&S	-	-	-	200	100
A/P	-	-	-	900	450
Other	-	-	-	89	66
Overheads	-	-	-	581	304
Total	**-**	**-**	**-**	**2,070**	**1,070**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Replace the Unit 7/70 Circulating Water Pumps
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.23307945
Status of Project	Planning
Estimated Start Date	January 2022
Estimated Completion Date	December 2022
Work Plan Category	Operationally Required

Work Description:
This project will replace the two (2) East River Unit 7/70 Circulating Water Pumps with two (2) new pumps with upgraded materials.

Justification Summary:
The East River Unit 7/70 Circulating Water Pumps supply cooling water for the condenser and auxiliary equipment. Both pumps take suction from the East River through the South Intake Tunnel. These pumps have been in service since 1955 and operate continuously when in the electric production mode. The unit was updated to include a steam send out mode in 1996. In the winter during steam send out mode, the turbine is isolated from the boiler. As a result, both circulating water pumps are out of service during this time. The pumps are Worthington, 54" MC-1 single stage vertical volute pumps with a capacity of 69,000 gallons per minute (gpm). Since the addition of the steam send out mode in 1996, these pumps have incurred a significant increase in wear because of chloride-induced corrosion exacerbated by water stagnation when the pumps are not in use. This project will replace the two (2) existing circulating water pumps with two (2) new pumps. The new pumps will include a material upgrade for superior resistance to chloride corrosion.

Supplemental Information:

- Alternatives:
  One alternative is to continue maintaining the existing pumps. This option is not recommended because the pumps are now reaching the point where they are no longer reasonably repairable.

- Risk of No Action:
  If not replaced, further degradation of the pumps could require significant repair in the near future and could result in unplanned equipment outages and derates.

- Non-financial Benefits:
  This upgrade will help to maintain system reliability; the new pumps will be resistant to chloride-induced corrosion.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	75	-
M&S	-	-	-	100	-
A/P	-	-	-	161	-
Other	-	-	-	23	-
Overheads	-	-	-	141	-
Total	**-**	**-**	**-**	**500**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Purchase Spare Traveling Screen
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22138200
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will purchase a spare traveling water screen to replace screens which must be removed from service at the East River Generating Station.

Justification Summary:
The East River traveling water screens located on the dock adjacent to the Franklin D. Roosevelt (FDR) Drive are used to limit the inflow of debris to the station salt water cooling systems used for the East River Units 6/60 and 7/70 condensers. Furthermore, the traveling water screens prevent the unwanted intake of marine life, which is a State Pollutant Discharge Elimination System (SPDES) violation, as these screens are specially designed to divert any impinged marine life back into the river safely.
There are five (5) screens, and we are able to operate four (4) screens temporarily allowing the 5th screen to be removed for repair or replacement. In recent years there have been failures of two (2) of the screens, requiring complete refurbishment or replacement. It is critical that any failure be addressed immediately; however, in the event of a significant failure that requires complete screen replacement, procurement and fabrication of a new screen can require months. In order to mitigate the risk of the long lead time in the event of a significant failure, a new screen should be purchased as a spare so that it can be immediately available to replace a failed screen.
Furthermore, additional screens have been found to need removal for maintenance due to corrosion. The addition of a spare screen will allow a direct replacement at the time of removal as opposed to mobilizing twice to remove and then re-install the repaired screen. The failing screen can be rebuilt to replace the spare screen in stores. Based on recent repairs, a spare will be needed in 2021.

Supplemental Information:

- Alternatives:
  One alternative to this project is to increase the inspection frequency of the traveling screens in order to anticipate replacement in a timely manner. This option is not recommended because it is not cost effective. This option would increase the maintenance costs associated with inspections.

- Risk of No Action:
  If left unaddressed, failure of any one (1) of the screens will affect the operation of East River Units 6/60 and 7/70.

- Non-financial Benefits:
  The purchase of a spare traveling screen will help to maintain system reliability. In the event of a single screen failure, a spare screen will allow the continuous operation of East River Units 6/60 and 7/70.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  This project is related to Aquatic Life Preservation.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	0	-	-
M&S	-	-	612	-	-
A/P	-	-	0	-	-
Other	-	-	0	-	-
Overheads	-	-	188	-	-
Total	**-**	**-**	**800**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Replace Traveling Screens 4 & 5
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.23307921
Status of Project	Planning
Estimated Start Date	January 2022
Estimated Completion Date	December 2022
Work Plan Category	Operationally Required

Work Description:
This project will replace Traveling Water Screens (TWS) No. 4 & No. 5 at the East River Generating Station. The new screens will be constructed of 316 stainless steel and coated with a coal tar epoxy. This construction is believed to be the most cost effective and the most resistant to biological fouling.

Justification Summary:
TWS No. 4 & No. 5 at East River were originally installed in 2013. Their original construction material was 316 stainless steel. However, in November 2016, TWS No. 4 & No. 5 were replaced with a high performance epoxy-coated carbon steel. Underwater inspections conducted during station outages in the fall of 2017 revealed that the coatings were in the incipient stages of failure at the bolted connections of the gull wings. The same coating system failures on TWS No. 6 & No. 7 in 2017 resulted in damage that required replacement of those screens.

Supplemental Information:

- Alternatives:
  One alternative to this project is to repair the existing screens only after failure. This option is not recommended because it risks plant operation and reliability. In addition, the repaired screens would be prone to failure, since the current material of construction is not as resistant to corrosion as the proposed new material.

- Risk of No Action:
  If no action is taken, the coating systems for TWS No. 4 & No. 5 will eventually fail and could result in failures of the screens. Loss of the TWS No. 4 & No. 5 will affect the operation of East River Units 6/60 and 7/70.

- Non-financial Benefits:
  This replacement will help to maintain system reliability. The new construction material and coating of the new screens will provide superior resistance to Microbial Influenced Corrosion (MIC).

- Summary of Financial Benefits:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships:
  This project is related to Aquatic Life Preservation.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	221	-
M&S	-	-	-	350	-
A/P	-	-	-	507	-
Other	-	-	-	0	-
Overheads	-	-	-	423	-
Total	**-**	**-**	**-**	**1,500**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Traveling Screen No. 8 Overhaul
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22138227
Status of Project	Planning
Estimated Start Date	January 2022
Estimated Completion Date	December 2022
Work Plan Category	Strategic

Work Description:
This project will remove and coat Traveling Water Screen No. 8 at the East River Generating Station with a corrosion resistant coating.

Justification Summary:
The existing traveling water screens currently in service on the East River Dock are extremely susceptible to corrosion caused by marine microbes, referred to as Microbial Influenced Corrosion (MIC). To mitigate this, the screens will be removed for coating with a corrosion resistant material.

Supplemental Information:

- Alternatives:
  One alternative to this project is to purchase a new traveling water screen only after a failure has occurred. This option is not recommended because it would risk plant operation and reliability.

- Risk of No Action:
  If left unaddressed, Traveling Water Screen No. 8 will continue to decay at an accelerated rate and require significant repair in the near future.

- Non-financial Benefits:
  This replacement will help to maintain system reliability. The coated screens will provide superior MIC resistance when compared to the existing.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships:
  This project is related to Aquatic Life Preservation.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	82	-
M&S	-	-	-	250	-
A/P	-	-	-	140	-
Other	-	-	-	0	-
Overheads	-	-	-	178	-
Total	**-**	**-**	**-**	**651**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	TR-7E Replacement
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.5EP0109
Status of Project	Planning
Estimated Start Date	January 2020
Estimated Completion Date	December 2020
Work Plan Category	Operationally Required

Work Description:
This project will replace the 13/69kV Generator Step-Up (GSU) Transformer No. 7 East (7E) with the system spare dedicated for East River Units 6/60 and 7/70. The existing fire protection system will be removed prior to the transformer removal and a new fire protection/detection system will be installed following the transformer replacement. The new system will consist of deluge piping, spray heads, and suppression and annunciation components. The project will also include the installation of a new moat and system foundation for oil containment and flood protection.

Justification Summary:
The transformer health assessment and the planned replacement program have ranked Transformer 7E at the East River Generating Station as one of the top candidates for replacement. The transformer has an extensive maintenance history and has environmental concerns. Inspections performed in the past have revealed several oil leaks. Attempts have been made to slow the oil leaks with epoxy repairs; however, the repairs have proven to have limited success due to new oil migrations observed through the epoxy. The transformer high voltage 69kV bushings are also degrading. Transformer 7E needs to be replaced, and a new moat and system foundation for oil containment and flood protection should be installed.

Supplemental Information:

- Alternatives:
  One alternative is to maintain and continue to operate the existing transformer. This option is not recommended because it increases the risk of an environmental impact and jeopardizes the reliability of East River Unit 7/70.

  A second alternative is to replace the transformer radiators only. This would eliminate the radiator oil leaks but it would not address the degraded condition of the transformer core and coil. Therefore, this option is not recommended.

- Risk of No Action:
  Not implementing this project will increase the risk of an environmental impact and will jeopardize the reliability of East River Unit 7/70 electric production.

- Non-financial Benefits:

This project will help maintain the reliability of the East River Generating Station, reduce maintenance associated with the transformer, and reduce the risk of an environmental impact.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	7	-	27
M&S	-	-	-	917	-	617
A/P	-	-	-	-	-	5
Other	-	-	-	-	-	39
Overheads	-	-	-	264	-	140
Total	-	-	-	**1,188**	-	**827**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	3,000	-	-	-
M&S	-	240	-	-	-
A/P	-	900	-	-	-
Other	-	144	-	-	-
Overheads	-	2,716	-	-	-
Total	**-**	**7,000**	**-**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	East River Units 60 and 70 O2 Trim
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.23307303
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will purchase and install Multi-channel Oxygen (O_2) Analyzers to replace the two (2) existing single channel analyzers on each of the East River Units 6/60 and 7/70.
This project will install four (4) O_2 probes (two per analyzer) and an Auto Calibration Unit. For each unit, all four (4) O_2 probe measurement signals and probe fault signals will be brought into the Ovation Distributed Control System (DCS), for use in creating reliable O_2 probe selection and control logic.

Justification Summary:
East River Units 6/60 and 7/70 currently have inadequate O_2 measurement systems for the stacks. These measurement systems are used to adjust the airflow to the units in order to obtain adequate combustion, and are therefore an integral component of emissions control.
The current system only provides two (2) O_2 measure probes for each unit; one (1) on the East side and one (1) on the West side. Under the current conditions, the failure of an O_2 probe will result in a significant decrease in operational efficiency of a unit and could result in a unit derate. The boilers in other Con Edison facilities are equipped with multiple O_2 probes to mitigate the risk of a single point of failure. The inadequacy of the current design (identical on each unit) was brought to light in 2017, when a failed O_2 probe resulted in a derate of East River Unit 6/60.

Supplemental Information:

- Alternatives:
  An alternative would be to use one (1) Multi-channel O_2 Analyzer to save on the cost of an additional analyzer (all four O_2 probes could be tied into one analyzer). The cost savings would be minimal, while the risk would be that the failure of one (1) analyzer could cause severe operational issues with the unit.

- Risk of No Action:
  If no action is taken, it could negatively impact operational efficiency or result in a unit derate.

- Non-financial Benefits:
  This project will help to maintain the reliability of East River Units 6/60 and 7/70 by mitigating the risk of an equipment failure that could result in a unit derate.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	160	-	-
M&S	-	-	95	-	-
A/P	-	-	25	-	-
Other	-	-	16	-	-
Overheads	-	-	163	-	-
Total	**-**	**-**	**459**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Replace Legacy Control Systems
Project Manager	Brian Manzino
Hyperion Project Number	PR.22138205
Status of Project	Planning
Estimated Start Date	January 2020
Estimated Completion Date	December 2020
Work Plan Category	Operationally Required

Work Description:
This project will upgrade the Programmable Logic Controllers (PLCs) for the Gas Turbines (GTs) at the Hudson Avenue Generating Station. The existing ControlLogix L61 processor was discontinued by the manufacturer, Rockwell Automation, in 2016 and will soon be obsolete. This project will replace the processor for each GT with the latest offering from Rockwell Automation, and transfer the existing programming into the new processor. Any incompatible input/output (IO) cards will also be upgraded with the processor.

Justification Summary:
Rockwell Automation's support for the obsolete hardware is limited. Failure of this device could lead to an extended shut down of the GTs until a replacement is located, purchased, and installed. While Con Edison has some spare components in stock, the Company does not have a spare ControlLogix L61 processor. Furthermore, investment in additional spare components is not cost effective at this time because any purchase of a ControlLogix L61 processor would be a refurbished product with limited warranty.

Supplemental Information:

- Alternatives:
  One alternative is to replace the ControlLogix with another vendor's equipment. This option would require re-terminating the existing IO cables. Once the cabling is installed, a full IO loop check would be required to verify that the wires were landed in the correct locations. Programming of the new logic would also need to be checked to confirm that it functions in the same manner as the existing logic. This option is not recommended because the additional labor for wiring, loop checks, and programming would dramatically increase the overall cost of the project.

- Risk of No Action:
  If no action is taken and one of the current PLCs were to fail, it could lead to an extended shut down of that GT until a replacement is located, purchased, and installed. This is not recommended because of the known obsolescence of the system and the history of past failures.

- Non-financial Benefits:
  This project will help to maintain reliability of the Hudson Avenue GTs by installing the latest supported hardware, and minimizing the risk of an extended forced outage in the event of a hardware failure.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Order of Magnitude Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Request by Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	30	-	-	-
M&S	-	9	-	-	-
A/P	-	175	-	-	-
Other	-	4	-	-	-
Overheads	-	82	-	-	-
Total	**-**	**300**	**-**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Replace Steam Pressure Control Valve
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.23307987
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will upgrade the 6" self-sustaining steam pressure control valve located on the Tank Farm Fuel Oil Heaters at the East River Generating Station. The valve and its positioner will be replaced with the latest offering from Emerson and will be Distributed Control System (DCS) ready.

Justification Summary:
Because the existing valve is not connected to the DCS to provide position indication to the Operator, it requires additional focus from maintenance to log its position and perform calibrations. The maintenance procedure for the valve is not consistent with other DCS connected devices and it continues to malfunction.

Supplemental Information:

- Alternatives:
  One alternative to this project is to continue operating with existing conditions. This option is not recommended because the existing valve and its positioner will continue to malfunction and station personnel will need to continue dedicating additional man-hours towards maintenance of the valve.

- Risk of No Action:
  Not replacing the existing valve and upgrading its positioner with DCS controlled elements will continue to cause malfunctions, and station personnel will need to continue dedicating additional man-hours towards maintenance of the valve.

- Non-financial Benefits:
  Upgrading the valve to similar systems installed elsewhere in the station will improve the station's Human Performance Improvement (HPI) metrics and maintenance program.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	50	-	-
M&S	-	-	15	-	-
A/P	-	-	24	-	-
Other	-	-	2	-	-
Overheads	-	-	50	-	-
Total	**-**	**-**	**141**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Replace GT1 GE Relays
Project Manager	Jason Muneton
Hyperion Project Number	PR.23307999
Status of Project	Planning
Estimated Start Date	January 2022
Estimated Completion Date	December 2022
Work Plan Category	Operationally Required

Work Description:
This project will replace the General Electric (GE) generator relays for Gas Turbine 1 (GT1) at the 59th Street Generating Station. The existing relays are GE type G60 and GE SR489 generator protection relays as primary and secondary protection. This project will replace the SR489 relay with the SEL 300 G relay. This will maintain redundant protection with two different relay types.

Justification Summary:
The GE generator relays type SR489 for GT1 have been identified as cyber security risks and need to be replaced. The cipher text of the user-configured password can be decrypted directly from the front of the devices or remotely through Modbus or a device web page. A GE security advisory notice was issued and an internal Con Edison audit identified the aforementioned relays. These relays have experienced numerous component failures over the last few years. In addition, their software interface is obsolete and we can no longer communicate with these relays using Corporate Information Technology (IT) approved devices. Current versions of the Windows operating system do not work with the original relay interface software. GE considers these devices obsolete and has no software upgrades to allow these devices to interface with current operating systems.

Supplemental Information:

- Alternatives:
  One alternative is to use new GE G60 relays to replace the SR489 relay, which is obsolete. This option is not recommended because it would not provide redundant protection with two different relay types.

- Risk of No Action:
  If no action is taken and the relays were to be compromised, GT1 could be unavailable for normal operation or for a "Black Start", which is a commitment to the PSC. The device is considered obsolete and could require more maintenance to keep functional.

- Non-financial Benefits:
  The new relays are microprocessor based and have oscillography/event reporting capability. During any system events in the station or during generator trip outs, the relay can provide fault/diagnostic information for analysis of events. This will provide an analytical tool to operations and engineering to analyze events.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Refer to GE ICS-CERT Advisory ICSA-17-117-01B last revised July 25, 2017: GE Multilin G489 Generator Management Relay. Model #489-P5-HI-A20-E. Firmware 3.0, Boot Rev 3.0, Hardware Version J.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using the cost of similar relay replacements for Unit 1 and Unit 2 at East River.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	10	-
M&S	-	-	-	9	-
A/P	-	-	-	70	-
Other	-	-	-	0	-
Overheads	-	-	-	31	-
Total	**-**	**-**	**-**	**120**	**-**

Schedule 5:

EP Capital White Papers

Environmental

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	No. 2 Oil Conversion
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.23317082, PR.23317090, PR.23317092
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	January 2023
Work Plan Category	Regulatory Mandated

Work Description:
This project will upgrade the Tank Farm fire protection system at the East River Generating Station, including upgrades to the tank internal foam system, monitoring system, and installation of a redundant water supply from a separate city water main. The four (4) East River fuel oil heaters located on top of the fuel oil storage tanks No. 2 and 3 will be removed and fuel oil piping will be added. In addition, the four (4) supply pumps will be replaced with pumps sized for compatibility with lower viscosity oil.

Justification Summary:
The New York City Department of Environmental Protection (NYCDEP) issued new rules regarding emissions from boilers and burners using No. 6 and No. 4 fuel oil. By 2020, users will no longer be able to renew their certificate of operation for No. 6 oil, and by 2025 No. 4 oil will be prohibited. This oil conversion project is required to meet compliance with the new NYCDEP regulation.

Supplemental Information:

- Alternatives:
  Given that the project is mandatory, there are no alternatives to completing the project.

- Risk of No Action:
  If the oil conversion project is not completed, there is a risk that the Company will incur fines for not being in compliance with the NYCDEP regulation.

- Non-financial Benefits:
  Completing this project will support the Company in maintaining regulatory compliance with the NYCDEP.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Similar oil conversion projects will be completed at each generating facility.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	0	225	835
M&S	-	-	573	3,761	1,311
A/P	-	-	0	850	2,050
Other	-	-	0	86	691
Overheads	-	-	177	1,579	1,882
Total	**-**	**-**	**750**	**6,500**	**6,770**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Replace Dock Transformer
Project Manager	Jason Muneton
Hyperion Project Number	PR.23307979
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Strategic

Work Description:
This project will replace the oil-filled transformer on Pier 98 at the 59th Street Generating Station with a dry type transformer to eliminate environmental risk.

Justification Summary:
59th Street transformers TR1, TR2, and TR3 are located on the dock above the Hudson River and provide power to the Heat Exchanger system which cools the West 49th Street cable cooling plants. Transformers TR2 and TR3 are dry type transformers. Transformer TR1 was also a dry type transformer until it failed in the 1990s. It was replaced with an oil filled network distribution transformer and does not have a fire protection system. This transformer is filled with silicon oil and barricaded by a 3" high metal moat for secondary containment. If there is a significant failure of the transformer, there is a risk of spilling 410 gallons of oil into the Hudson River. The transformer should be replaced with a dry type transformer to eliminate the potential for an oil spill.

Supplemental Information:

- Alternatives:
  One alternative to this project is to raise the metal moat wall height. This alternative could reduce the risk of an oil spill, however it cannot eliminate the risk 100 percent.

- Risk of No Action:
  If no action is taken, there is risk of a significant transformer failure occurring without adequate fire protection or containment, which could result in an oil spill.

- Non-financial Benefits:
  This project aims to remove any potential risk of an oil spill. The dry type transformer does not contain oil, and therefore will not cause an oil spill.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	10	-	-
M&S	-	-	700	-	-
A/P	-	-	31	-	-
Other	-	-	20	-	-
Overheads	-	-	239	-	-
Total	**-**	**-**	**1,000**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Cable Cooling Dielectric Leak Detection
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22636931
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:

This project will install a dielectric oil detection system in the fresh water Cable Cooling water head tanks at the East River Generating Station. The leak detection system will monitor for the presence of dielectric fluid in the high point in the system, to determine if there is an oil leak. Redundant oil sensors will be installed in each Cable Cooling head tank. The leak detection system alarm signals will tie into the existing Cable Cooling water control panel which will annunciate a category alarm in the East River Unit 7/70 Distributed Control System (DCS). The existing Cable Cooling control panel will be modified to accept the signals from the new dielectric oil detection system. A "Heat Exchanger Trouble" category alarm indicating any abnormal occurrence in the heat exchanger facility is already provided in the central Control Room. The category trouble alarm annunciates to the East River Unit 7/70 Control Room Operator. The benefit of installing a leak detection system is to provide operators immediate notification of an oil leak in a Cable Cooling heat exchanger to mitigate the possibility of a State Pollutant Discharge Elimination System (SPDES) event. The existing piping connections from the two (2) head tanks to the Cable Cooling Oily Water Holding Tank will have to be repaired and modified as needed. The Oily Water Holding Tank will be repaired and/or replaced as needed. Redundant Oil Level instrumentation will be installed on the Oily Water Holding Tank.

Justification Summary:

The East River Cable Cooling Water System does not have a dielectric fluid leak detection system presently installed within the Generating Station that provides discreet indication to the Control Room Operator that an oil leak is present. The fresh water cooling system interfaces with dielectric fluid in three (3) heat exchangers located in the 15th Street Public Utility Regulated Station (PURS) facilities, which provide cooling for feeders 35Q, M54, and M55. The original design of the Cable Cooling Water System included an in-line turbidity meter installed at the discharge side of the freshwater cooling pump. The turbidity meter has not been functional for a long period of time. Additonally, a turbidity meter does not provide the station with the best protection because oil has a density that is less than water and can accumulate at the high point in the system (fresh water head tank). Currently, the design of the Cable Cooling Water System leaves the station vulnerable to an undetected oil contamination event, with the exception of the high head tank level indicator. If there was an unnoticeable oil leak into the fresh water side of the system, the fresh water head tank would overflow into the Oily Water Holding Tank. The Oily Water Holding Tank can hold 2,800 gallons before overflowing onto the plant basement floor or into the salt water system, leading to a potential SPDES violation.

Supplemental Information:

- Alternatives:
  An alternative solution is to go back to the original system design and install an in-line turbidity meter at the discharge of the fresh water pumps, tying the device alarming capabilities into the Cable Cooling alarm panel for immediate annunciation of an oil condition. This option is not recommended, because of maintenance considerations with a pressurized online system, as well as concern about device sensitivity and accuracy in detecting oil levels.

- Risk of No Action:
  If a dielectric oil detection system is not installed, there is a risk that a dielectric fluid leak could occur leading to a SPDES violation.

- Non-financial Benefits:
  A new dielectric oil detection system installed on the head tanks will improve environmental performance of the Cable Cooling Water System.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	40	-	-
M&S	-	-	35	-	-
A/P	-	-	5	-	-
Other	-	-	2	-	-
Overheads	-	-	43	-	-

-

Schedule 6:

EP Capital White Papers

Safety and Security

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Fire Alarm System in Unit 6/7 Plant Areas
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.2EP4200
Status of Project	Planning
Estimated Start Date	January 2019
Estimated Completion Date	December 2020
Work Plan Category	Operationally Required

Work Description:
This project will perform a hazard analysis of the fire protection systems within the East River Units 6/60 and 7/70 areas. The review will evaluate the existing fire protection systems, as well as the need for new fire protection systems in locations that currently do not have fire protection. This project will make upgrades based on the recommendations from a fire hazard analysis report, and also install a centralized fire alarm control system to interface with the station's various fire detection/protection systems to provide automatic fire detection coverage to all plant areas deemed critical.

Justification Summary:
The purpose of this project is to centralize and improve the station fire protection systems to help reduce risk. The details and extents of the specific modifications/options to be implemented are still under review. Based on recommendations from the Fire Department of the City of New York (FDNY) Bureau of Fire Prevention, the new New York City Building Code requires that all new buildings greater than 75 feet in height install a building-wide fire detection system. Though not required, due to this being an existing building, a fire alarm and detection system would provide an early warning of a possible fire condition that may require rapid response to minimize equipment damage and protect personnel safety. Good engineering practices to help mitigate risk in certain areas of the plant, along with the FDNY's recommendation (in conjunction with the Terminal Board Room Fire Detection project), suggest that improved coverage and other potential fire protection system upgrades in the plant are warranted.

Supplemental Information:

- Alternatives:
  One alternative is to maintain the status quo. This is not recommended as good engineering practice warrants trying to reduce risks where applicable.

- Risk of No Action:
  If no action is taken, the station would lack an early warning alarm of fire in some areas of the building, risking increased collateral damage in the event of a fire.

- Non-financial Benefits:
  The fire detection systems, when combined with an emergency response and evacuation plan, can significantly minimize damage to equipment and improve public and employee safety. Upgrading the system will help provide faster response to a fire, potentially minimizing equipment damage and reducing associated repair costs.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  The fire protection hazard analysis study will evaluate each fire detection and suppression system and the separation of plant areas, in order to determine the station's ability to reduce the risk of fire propagation and provide recommendations to improve or upgrade these systems.

- Project Relationships (if applicable):
  This project is related to Replacement of Fire Pump #2 Control Panel and Terminal Board Room Fire Detection, which were completed previously.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	50	90	-	-	-
M&S	100	85	-	-	-
A/P	365	745	-	-	-
Other	25	190	-	-	-
Overheads	160	390	-	-	-
Total	**700**	**1500**	**0**	**0**	**0**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Install Access Platforms
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.20699084
Status of Project	Planning
Estimated Start Date	January 2020
Estimated Completion Date	December 2020
Work Plan Category	Strategic

Work Description:
This project will install permanent steel platforms in various locations associated with East River Units 6/60 and 7/70. This project will replace temporary wooden platforms, relocate steel structures to improve access, and modify or install fall protection at various plant locations.

Justification Summary:
Many existing equipment access platforms at East River Generating Station were built as temporary structures. These wooden temporary platforms do not provide adequate fall protection, and pose a fire hazard. Lack of proper access structures impedes the operator's ability to complete their rounds efficiently and safely, and also precludes effective maintenance in some areas. Replacing the temporary platforms with permanent steel structures will ensure compliance with the New York City Building Code.

Supplemental Information:

- Alternatives:
  One alternative is to relocate equipment to more accessible areas. This alternative would be very costly and would not address the safety and fire hazards.

- Risk of No Action:
  If the temporary structures are not replaced, safety concerns will remain. In addition to the personnel safety concerns associated with the temporary nature of the platforms, the wood increases the risk associated with fires at the station.

- Non-financial Benefits:
  By constructing new safety platforms, this project will improve personnel safety at the facility and help to maintain compliance with the New York City Building Code.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:

Fire rated wooden structures (e.g. access platforms) may be used on a temporary basis for a duration of less than one (1) year, per the New York City Building Code. However, existing wooden platforms have been in place for more than one (1) year and must be replaced with permanent steel platforms to comply with code.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  This effort is an on-going program to install permanent steel platforms at various areas of the station. Funding is requested annually until all platforms are installed.

Actual Funding Levels ($000):

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	123	-	-	-
M&S	-	-	5	-	-	-
A/P	-	-	-	-	-	-
Other	-	-	10	-	-	-
Overheads	-	-	128	15	-	11
Total	-	-	**267**	**15**	-	**11**

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	90	-	-	-
M&S	-	119	-	-	-
A/P	-	545	-	-	-
Other	-	200	-	-	-
Overheads	-	341	-	-	-
Total	**-**	**1,295**	**-**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Update ER Emergency Evacuation System
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22636941
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Strategic

Work Description:
This project will expand the East River Generating Station Public Address (PA) system and strobe system. The ability to promptly notify employees of an emergency or evacuation situation is time-critical, and current deficiencies can be addressed by expanding the existing system.

Justification Summary:
Review of semi-annual evacuation drills has identified two (2) key areas in the facility where employees are not able to hear emergency notifications. This can lead to personnel accountability delays during evacuations. The two (2) areas include the Tank Farm moat and the Dock extending from the West Tunnel Head House to the north end of the Screen House. These areas were not designed to have the emergency evacuation system installed, but have proven to be problematic during evacuation drills.

Supplemental Information:

- Alternatives:
  One alternative to this project is to modify existing communication racks by adding additional amplifiers and transformers, and upgrading the existing Uninterruptible Power Supply (UPS) units to serve the new speakers and strobe lights. This alternative is not recommended because it would require shutting down the existing communication system to make modifications, and because it is less cost effective due to the additional hardware.

  A second alternative is to install a new communication rack inside of the South Steam Station to cover all new areas. This option is not recommended because it would require the installation of a new rack, new UPS, additional fiber optic cable runs, and additional floor space for the new rack and UPS.

- Risk of No Action:
  The Tank Farm and the Screen House areas currently lack emergency evacuation system coverage. Additional emergency evacuation system coverage is needed inside the West Tunnel Head House, Tunnel, East Transfer Head House and the Dock area. If the emergency evacuation system is not installed, there is a safety risk of employees not being notified of emergencies in time.

- Non-financial Benefits:
  This project will provide an integrated PA system for emergency notifications in the locations noted that will comply with current Occupational Safety and Health Administration (OSHA) regulations (29CFR 1910.120(q) and 29CFR 1910.38(a)) and Corporate Safety Procedures (CSP 24.01 and 24.02). This project will therefore minimize safety risk due to the inability to hear emergency notifications. These improvements will lead to a safer work environment and will help improve the confidence and morale of Con Edison personnel.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Engineering performed a field walk with Operations personnel at the East River Generating Station. During this field walk, the team evaluated the need for an emergency evacuation system in the Screen House, Tank Farm, West Tunnel Head House, Tunnel, and Dock area. It was observed that the Tank Farm and Screen House areas lacked emergency evacuation system coverage. (The current emergency evacuation system does not extend to the Tank Farm and Screen House areas.) Additionally, the emergency evacuation system inside the West Tunnel Head House, Tunnel, East Transfer Head House and the Dock area needs to be supplemented.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	60	-	-
M&S	-	-	100	-	-
A/P	-	-	202	-	-
Other	-	-	0	-	-
Overheads	-	-	138	-	-
Total	**-**	**-**	**500**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Repair Slabs Under Transfer House
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.22636800
Status of Project	Planning
Estimated Start Date	January 2021
Estimated Completion Date	December 2021
Work Plan Category	Operationally Required

Work Description:
This project will remove the first floor concrete slab of the East River Generating Station East Transfer House, and replace it with new steel grating. In addition, the steel stairs, which provide access from the Tunnel to the East Transfer House first floor, will be replaced.

Justification Summary:
Inspections of the underside of the East Transfer House first floor have revealed deteriorating structural conditions that need to be addressed. The conditions reported include spalled and delaminated concrete, as well as rusting and corrosion of the rebar and stairs. The potential for falling debris poses a safety concern for employees that access equipment in the area.
The East Transfer House provides the only means of access and egress to the East River Dock from the main operating areas of the plant via the Coal Conveyor Tunnel. The East River Dock contains critical equipment for plant operations, and the access-way is operationally required to be in service at all times.

Supplemental Information:

- Alternatives:
  One alternative to this project is to remove the slab, and provide a new stairway which bypasses the East Transfer House first floor and leads directly to the East River Dock from the Tunnel floor. This alternative is not recommended because it would be costly to relocate existing electrical and mechanical equipment that is installed on the East Transfer House first floor.

  A second alternative to this project is to remove access to the floor all together and seek an alternate means of access and egress to the East River Dock. This alternative is not recommended because it would be costly to relocate existing electrical and mechanical equipment installed on the floor, and it would require personnel to drive approximately a half mile to access a gated entrance at the property line with the New York City Parks property.

- Risk of No Action:
  If the floor is not replaced and deterioration continues to progress, workers will remain exposed to a safety hazard and equipment installed on the floor could become compromised.

- Non-financial Benefits:

This project will enhance employee safety by removing the deteriorated floor slab and installing new steel grating.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Engineer's Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	30	-	-
M&S	-	-	0	-	-
A/P	-	-	151	-	-
Other	-	-	0	-	-
Overheads	-	-	69	-	-
Total	**-**	**-**	**250**	**-**	**-**

X	Capital
	O&M

2019 – Steam Operations / Electric Production

Project/Program Title	Lube Oil Room Ventilation
Project Manager	Joseph O'Hagan
Hyperion Project Number	PR.20989606
Status of Project	Planning
Estimated Start Date	January 2022
Estimated Completion Date	December 2022
Work Plan Category	Operationally Required

Work Description:
This project will upgrade the ventilation system for the lube oil store room at the East River Generating Station. Currently, there is inadequate airflow across the room with only one (1) supply air grille located approximately 12" above grade. A new louver, supply fan, electric duct heater and ductwork will be provided to discharge outside air at the ceiling elevation of the storage room. A new exhaust fan will be installed and the ductwork will be modified to include two (2) exhaust air outlets in lieu of one (1) to ensure that adequate airflow across the room is achieved.

Justification Summary:
The New York City Fire Code indicates that oil storage rooms shall be equipped with adequate ventilation to remove hazardous vapors. While the existing system does not violate the New York City Fire Code, the duct work configuration does not allow for uniform air flow across the room and does not use outside air to ventilate the room. The existing lube oil storage room ventilation system will be redesigned to ensure air movement that adequately removes hazardous vapors. The ventilation system will be monitored to indicate and transmit the status of the fans to the station personnel.

Supplemental Information:

- Alternatives:
  An alternative to this project is to leave the existing system in place, remove the exterior egress door, and install a weather proof louver in its place. This would ensure that hazardous vapors would not accumulate in the room. The sprinkler system, however, would have to be modified from a "wet" to "dry" system to prevent freezing of the interior standpipes during the winter. This would require the installation of a deluge valve, a heat detection system, and manual emergency annunciation devices to alert the operator of a trouble condition. This option is more costly and is therefore not recommended.

- Risk of No Action:
  Not upgrading the ventilation system could result in a malfunction or failure of the existing ventilation system. A failure of the existing ventilation system can cause an accumulation of hazardous vapors within the room creating an unsafe environmental condition.

- Non-financial Benefits:
  The redesigned ventilation system will help to maintain adequate air flow and allow remote monitoring by station personnel, which will improve employee safety.

- Summary of Financial Benefits (if applicable) and Costs:
  Not applicable.

- Technical Evaluation/Analysis:
  Not applicable.

- Project Relationships (if applicable):
  Not applicable.

- Basis for Estimate:
  The funding for this project was determined using an Appropriation Estimate.

Actual Funding Levels ($000):

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	-	-	-	-		-
M&S	-	-	-	-		-
A/P	-	-	-	-		-
Other	-	-	-	-		-
Overheads	-	-	-	-		-
Total	-	-	-	-		-

Future Elements of Expense

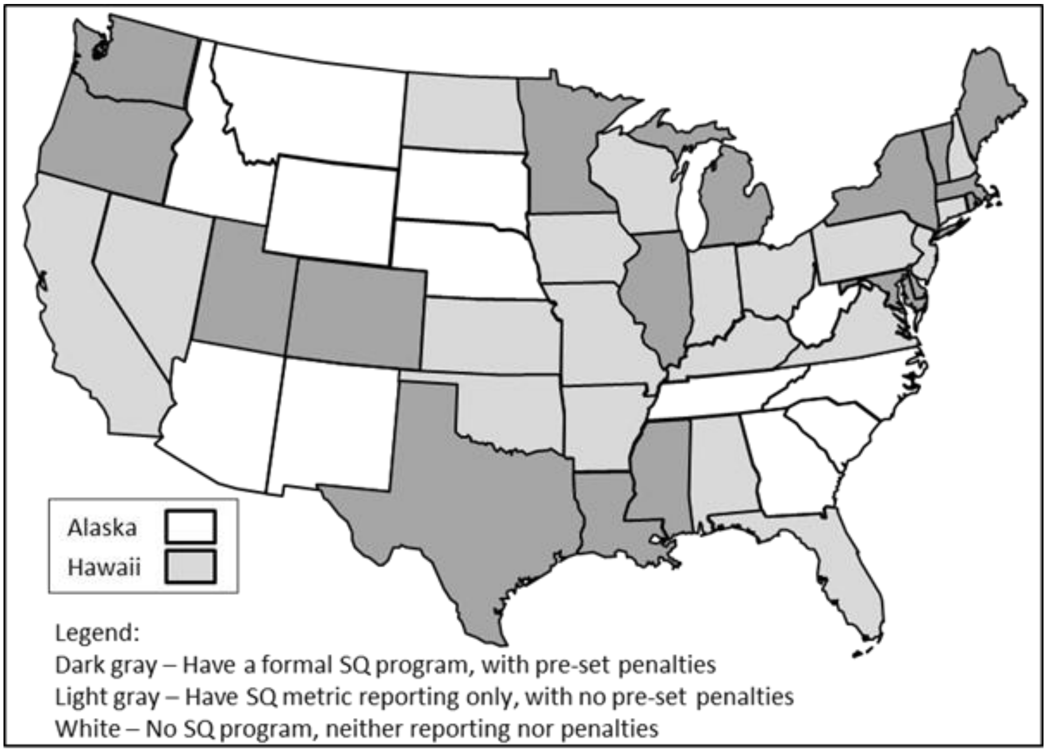
EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	-	-	-	75	-
M&S	-	-	-	100	-
A/P	-	-	-	200	-
Other	-	-	-	22	-
Overheads	-	-	-	153	-
Total	**-**	**-**	**-**	**550**	**-**

Exhibit__(EIOP-12)

T&D Special Issues

Schedule 1:

SQ Regulation by State



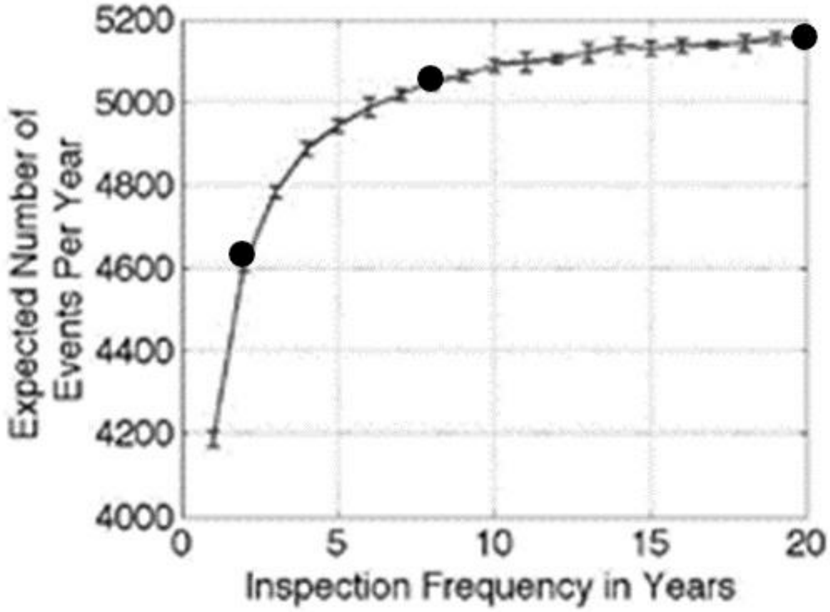
This graphic shows a map of the United States that is colored with different shades of gray to indicate which states have performance-based ratemaking mechanisms that include measures of electric service reliability explicitly

State	Regulation	Electric Reliability Metrics
California	Penalties	SAIDI, SAIFI
Colorado	Penalties	SAIDI
Delaware	Penalties	SAIDI
D.C.	Penalties	SAIDI, SAIFI
Illinois	Penalties	SAIDI, SAIFI, CAIDI
Louisiana	Penalties	SAIDI, SAIFI, CAIDI
Maine	Penalties	SAIDI, SAIFI, CAIDI
Maryland	Penalties	SAIDI, SAIFI, CAIDI
Massachusetts	Penalties	SAIDI, SAIFI, CAIDI
Michigan	Penalties	Other (CEMI, CELID)
Minnesota	Penalties	SAIDI, SAIFI
Mississippi	Penalties	CAIDI
New York	Penalties	SAIFI, CAIDI
Oregon	Penalties	SAIDI, SAIFI, CAIDI, MAIFI
Rhode Island	Penalties	SAIDI, SAIFI
Texas	Penalties	SAIDI, SAIFI
Utah	Penalties	SAIDI, SAIFI
Vermont	Penalties	SAIFI, CAIDI
Washington	Penalties	SAIDI, SAIFI
Alabama	Reporting only	None
Arkansas	Reporting only	None
Connecticut	Reporting only	None
Florida	Reporting only	None
Georgia	Reporting only	None
Hawaii	Reporting only	None
Indiana	Reporting only	None
Iowa	Reporting only	None
Kansas	Reporting only	None
Kentucky	Reporting only	None
Nevada	Reporting only	None
North Dakota	Reporting only	None
Ohio	Reporting only	None
Oklahoma	Reporting only	None
Pennsylvania	Reporting only	None
Virginia	Reporting only	None
Wisconsin	Reporting only	None
Alaska	None	None
Arizona	None	None
Idaho	None	None
Montana	None	None
Nebraska	None	None
New Hampshire	None	None
New Mexico	None	None
North Carolina	None	None
South Carolina	None	None
South Dakota	None	None
Tennessee	None	None
West Virginia	None	None
Wyoming	None	None

This table shows the states that have performance-based ratemaking mechanisms, the electric reliability metrics used.

Schedule 2:

Analytics for Power Grid Distribution Reliability



Schedule 3:

Remote Inspection Tools

This image was acquired using a borescope on an underground structure with sufficient image detail to verify a properly installed end cap.

Schedule 4:

Infrared Image Acquired from SOS Device

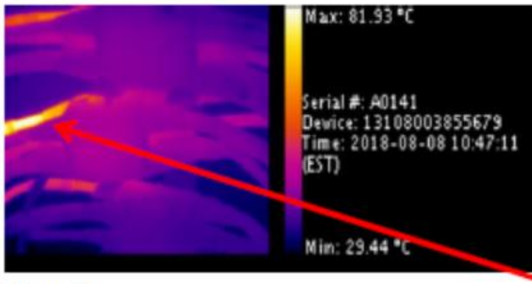


Figure 2

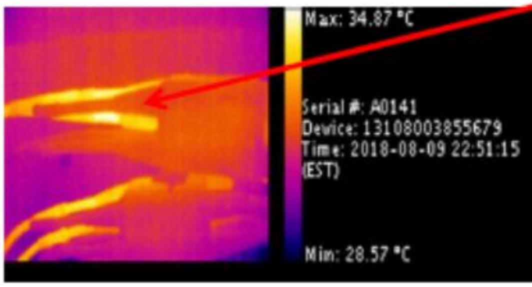
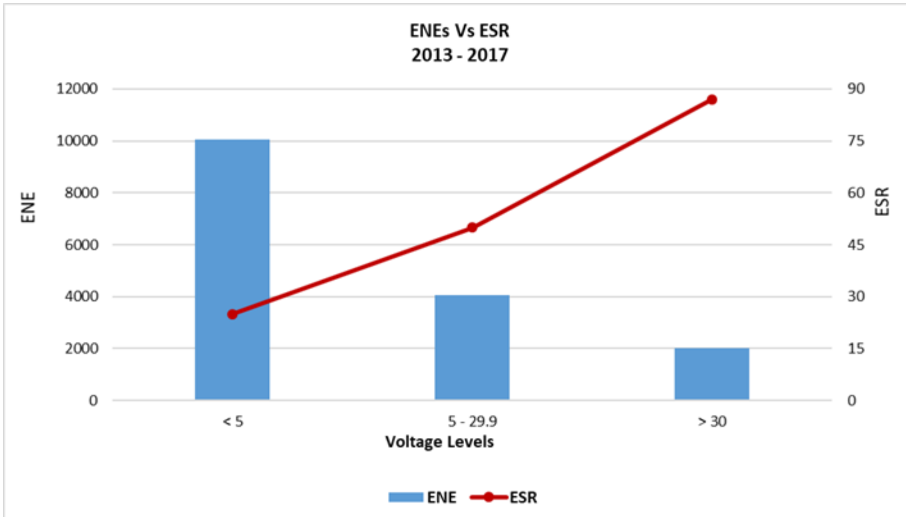


Figure 3

Infrared images reported real time from a remote monitoring device. Figure 2 shows cable connection with an elevated temperature (82° C) due to failing connection. Figure 3 shows the same connection post repair operating correctly

Schedule 5:

Energized Equipment vs Electric Shock Reports



	Capital
X	O&M

2020 Customer Energy Solutions

Project/Program Title	Energy Efficiency
Project Manager	Vicki Kuo
Hyperion Project Number	23221305, 23171766, 23171762, 23171755
Status of Project	In-Progress
Estimated Start Date	In-Progress
Estimated Completion Date	Open ended
Work Plan Category	Strategic

Work Description:

The Company's proposal works toward supporting: (i) State policy objectives, including the goals of New York State's Reforming the Energy Vision ("REV") and the goals in the April 2018 New Efficiency: New York ("NE:NY") whitepaper[1] (ii) the City's policy goals of an 80% reduction in greenhouse gas ("GHG") emissions by 2050, and (iii) plans articulated in the Company's recent Distributed System Implementation Plan ("DSIP")[2] to advance distributed resources, including energy efficiency ("EE"). The Company did not have adequate time to complete its review and evaluation of its EE program in light of the timing of the December 2018 *New Efficiency: New York* ("NENY*") Order Adopting Accelerated Energy Efficiency Targets* ("EE Order")[3] prior to finalizing its revenue requirements. Accordingly, the Company may adjust its EE programs at the preliminary update stage of these proceedings. Con Edison's proposal herein is seeking to grow EE savings to achieve a higher level of GHG reductions cost-effectively, spur and drive innovation in the market, and create customer and system benefits.

The Company has significantly increased program achievements and exceeded the maximum EE targets in 2017 and expects to have done so again in 2018 through a portfolio of products and services offered to a diverse group of customers. Con Edison intends to continue the success of its EE programs, achieved by the regulatory framework that allowed the Company to moderate bill impacts for customers through recovery of EE costs as regulatory assets amortized over 10 years, supplemented with Earnings Adjustment Mechanisms ("EAMs"), to drive achievement of additional energy and demand savings cost-effectively. The portfolio proposed herein is designed to increase its savings achievement to 1.5% of sales over a three-year period ending 2022, ramping up from 0.6% of sales in 2017. This growth aligns the Company with State policy objectives. The targets set by the State in the NE:NY White Paper include 185 TBtu site energy savings, and an annual reported electricity savings reaching 3% of investor-owned utility ("IOU") sales in 2025. These targets are in furtherance of the State's goals of:

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[1] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative* ("Energy Efficiency Initiative"), New Efficiency: New York, filed April 26, 2018.
[2] Case 16-M-0411, *In the Matter of Distributed System Implementation Plans*, Second Distributed System Implementation Plan, filed July 31, 2018.
[3] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative* ("Energy Efficiency Initiative"), New Efficiency: New York, Order Adopting Accelerated Energy Efficiency Targets, issued and effective December 13, 2018.

- 40% reduction in GHG emissions from 1990 levels by 2030,
- 50% electricity from renewable sources by 2030, and
- 600 trillion BTU increase in statewide EE.

This white paper describes the program and labor expenditures necessary to implement an EE portfolio to continue the ramp up and implement additional demand management programs, such as non-wires solutions ("NWS"), both under the existing regulatory framework of the current rate plan. The Company is also proposing performance incentives through EAMs as described in the Customer Energy Solutions ("CES") Panel testimony.

The Company's portfolio reflects and builds upon more than a decade of experience running successful and cost-effective EE programs that enables customers to better manage their energy use and save on their bills. The programs have transformed the customer experience with the utility and provided services beyond traditional electric and gas delivery. The Company is expanding its EE portfolio while balancing the set of priorities discussed in the NE:NY White Paper.

In expanding Con Edison's programs, the Company plans to implement programs for reaching all major segments of our customers – Commercial and Industrial, Multifamily, and Residential. For example, the Company plans to implement: (i) commercial offerings for large and small commercial customers by targeting the capital funding cycles over multiple years, (ii) multi-family initiatives seeking to reach more of these customers and enhancing ability to retrofit multi-family buildings through partnership with programs such as the City's Retrofit Accelerator, while also recognizing complexities such as tenant-landlord split incentives, and (iii) residential sector initiatives to address a highly fragmented market. Even with such planned expansion, Con Edison anticipates uncertainties that can impact achievements in the upcoming years, such as lighting code changes that could adversely affect reported savings in later years. In addition, ramping up will require more funding to drive adoption of more expensive, slower turning over measures such as heating, ventilation, and air-conditioning ("HVAC").

Under the Company's proposal, the three primary segments of our customers are reached through the following four primary delivery channels: (i) commercial and industrial ("C&I") programs focused on larger commercial customers, (ii) small business programs focused on smaller commercial customers, (iii) multifamily programs focused on multiple dwelling buildings with five or more homes in the building, and (iv) residential programs focused on one to four family homes, which are designed to meet each customer group's particular needs. However, efficiency offerings and delivery channels are not static; they are managed and revised with continuous improvement and innovative solutions as key priorities.

Con Edison coordinates in partnership with the New York State Energy Research and Development Authority ("NYSERDA"), and plans to continue to work together to leverage pilot offerings, furthering the reach of EE investments. Such partnerships can help develop new markets, achieve synergies to increase effectiveness, and deliver energy savings over the longer term needed to achieve robust policy goals. These efforts also seek to facilitate development of the market over time for increased adoption, maximize value to customers, incrementally advance market-based initiatives, and generally assure complementary or reinforcing efforts. The resultant outcomes are intended to transform markets and improve EE adoption over many years, beyond what uncoordinated efforts could achieve on their own.

The Company is also constantly seeking to more efficiently use available financial resources by striving to minimize costs where possible while maintaining ambitious levels of energy savings achievement. The Company plans to continue to work to reduce costs and expects in the short term to benefit from those efforts in some of its programs, enabling more customers to participate in and benefit from those offerings. Recent success in achieving cost efficiencies include administering portions of the C&I initiative internally, targeting interventions at different levels of the vertical supply chain, leveraging REV demonstration projects including the Online Marketplace, and developing multiyear partnerships with large commercial customers. However, despite efforts to reduce unit costs, the Company is also aware of countervailing upward pressure on costs, for example, from: (1) the drive for deeper savings and diversification beyond lighting, (2) reductions in reported energy savings due to baseline shifts driven by building and manufacturing code improvements, and (3) the need to seek EE adoption among harder-to-reach customers and incent adoption of more expensive measures that have longer pay-back periods for customers.

Con Edison seeks to play a leadership role in innovative program design and implementation while also integrating EE as part of the Company's core business. The suite of programs delivered throughout the Company initiatives seeks to provide Con Edison customers with an energy system that is cleaner and more sustainable. Further, integration of EE into system planning presents other highly cost effective opportunities to incorporate clean energy into the power grid and defer infrastructure, such as with NWS.

Programs Overview:

Con Edison will strive to engage customers and provide them with greater control over their energy choices. Under the broad commercial and residential segment umbrella portfolios, the Company's programs will be tailored to each customer segment's particular needs and, in some cases, include other complementary pilot initiatives, such as those by NYSERDA in that customer segment. The offerings described below are not static, but rather evolving strategies that respond to market changes so as to serve a broad and diverse set of customers. Initiatives are designed to deliver efficiency savings and meet customer expectations in an effective manner and to offer multiple opportunities for engagement with the Company and market partners.

C&I

Con Edison plans to offer a robust suite of products and services to commercial electric and gas customers of various sizes and business types. Recognizing the distinct nature of commercial customers, the Company intends to continue to offer market-based offerings through which customers may address their particular business objectives and constraints. These include large C&I prescriptive incentives, *i.e.*, pre-set and fixed incentives on a per unit basis, C&I custom incentives, the Commercial Direct Install ("CDI") program providing incentives to smaller businesses, Instant Lighting focused on incenting lighting upstream in the supply chain, and Strategic Energy Partnerships targeting incentives to our larger energy consumers to adopt EE beyond efficient lighting. Further, the Company intends to launch new offerings focused on midstream and upstream delivery channels to incentivize EE measures in this sector.

The Company will also focus on identifying and engaging customers that are heavy energy users to help them adopt deeper EE and to assist with their reporting in compliance with the City's Local Law 84 that benchmarks energy consumption of such customers. Customer segment verticals, *i.e.*, a group of customers engaged in the same industry or type of activity, such as hospitals, schools, and the banking sector are some of the areas where Con Edison may see significant potential for savings. Working to secure longer term partnerships with some of the larger energy consumers in the service territory can be expected to produce considerable savings. The Strategic Energy Partnership is intended to engage such customers to incorporate EE into their medium and longer term capital planning and budgeting cycles.

The Company is further seeking to transform markets for efficiency measures through upstream C&I offerings for lighting and HVAC measures. These initiatives are part of a continuing and sustained effort to deliver innovative and market transformative programs.

The Instant Lighting Incentive Program ("ILIP") is an upstream lighting program currently open to commercial, small business, and multifamily customers. The Company intends to continue ILIP so customers can receive instant incentives on eligible ENERGY STAR®-certified and Design Lights Consortium-listed lamps at the distributor point of sale.

The Company expects to continue the CDI program, offering small to mid-size commercial customers with average peak demand of up to 300 kW, low to no-cost EE equipment upgrades for their businesses. In addition to light emitting diode ("LED") lighting and refrigeration measures, the program will includes gas measures, HVAC measures, controls, and cooking equipment to provide a more comprehensive set of energy solutions to this group of customers.

Residential

Con Edison will continue to approach the residential segment through a portfolio approach by developing a variety of electric and gas offerings aimed to service customers' distinct needs. The Company intends to further test and implement upstream interventions building on lessons learned from the residential electric and gas HVAC portfolio that has transitioned to an upstream model where incentive funds flow through the distributor to customers. An upstream program model engages the distributor and contractor and aligns their interest with more efficient equipment. And the Company expects the approach to be impactful because distributors and contractors often make HVAC recommendations to residential customers.

A core part of the residential portfolio is the Appliance Rebate program, offering rebates for energy efficient appliances including, but not limited to, eligible dishwashers, clothes washers, dehumidifiers, and room air conditioners. The Company intends to continue and evolve this program.

The Residential program introduced instant rebates on LEDs and smart thermostats through direct sales on Con Edison's Online Marketplace. The Online Marketplace was established as part of a REV Demonstration project in 2016 as a one-stop shop offering product comparisons by energy score and the aforementioned instant rebates on light bulbs and thermostats. The Company plans to transition the marketplace into the EE portfolio and continue to evolve the effort to provide cost-effective energy savings.

Con Edison launched a retail lighting program that offers discounted LEDs through select retailers in 2017. In 2018, the retail lighting program was expanded to include second tier retailers, such as drug stores and dollar stores where customers shop, and also distributed LEDs to low income customers through partnering food banks within Con Edison's territory. The Company will continue to grow the program to reach more customers to help them adopt more efficient products.

Additionally, Con Edison intends to continue the successful Smart Kids program that delivers kits containing LEDs, faucet aerators, and showerheads to fifth-graders across the service territory and pairs the issuance of the kits with an in-classroom EE lesson plan. The program is further expected to result in lasting market transformation as new generations of New Yorkers become aware of EE and learn about ways they can contribute towards sustainability.

Multifamily

The Multifamily Program promotes EE for existing multifamily electric and gas customers. This program is targeted to owners and property managers of residential buildings with five or more units. Customers in qualifying affordable buildings are also eligible for enhanced incentives. The Multifamily Program will continue to develop strategies to further enhance adoption of EE, including for customers in affordable rate buildings. The Company also intends to further facilitate retrofits of multi-family buildings through building on partnerships with programs such as the City's Retrofit Accelerator.

Customers will have the ability to apply for EE incentives, with both prescriptive, for both common area and in-unit measures, and custom rebates. For those buildings that need assistance in developing a plan for EE, the program offers on site assessments to identify areas of meaningful opportunity.

Test and Learn ("T&L")

The Company's ongoing T&L strategy is a systematic method of identifying, designing, and implementing new technologies, programs, initiatives, and campaigns. The Company uses the T&L strategy to identify new measures, uses, and delivery mechanisms for existing offerings, and to identify and test new programs and initiatives before full scale implementation is undertaken. As a T&L initiative reaches maturity, the Company will evaluate its long-term viability and potential for success, after which the initiative will either be scaled up, retired or retooled, as appropriate.

Current T&L initiatives that the Company plans to continue testing include the Midstream Retailer Incentive Program based on intervening just upstream of the customer, a new customer welcome program focused on new customers coming into the Company territory, residential and multifamily behavioral programs based on development of home energy reports detailing consumption information, Building Energy Performance commercial behavioral programs focused on using behavioral approaches in the C&I sector, and third party residential financing.

Beneficial Electrification

The Company is proposing a three-year beneficial electrification program, focused on increasing adoption of beneficial electrification technologies, such as air-source and ground-source heat pumps that (i) provide our customers with alternative options for heating especially considering customers impacted by gas moratoriums, (ii) reduce environmental emissions that advance State, New York City, and other local or municipal decarbonization goals, including an 80 percent reduction in GHG emissions by 2050, and (iii) generally decrease peak energy usage and increase off-peak energy usage. The Company seeks to also expand electrification to customers that currently use a non-jurisdictional fuel, such as oil, gasoline, kerosene, or propane and incentivize them to convert to an electrification technology. In developing and implementing the beneficial electrification program, the Company plans to work with key stakeholders such as NYSERDA, New York City, and Westchester County, so Company efforts are complementary to other efforts related to beneficial electrification in the Company territory.

The Company may, however, update its beneficial electrification proposal after further evaluation of the EE Order and Commission decision on the proposed Non-Pipeline Solutions ("NPS") portfolio. NPS is a part of the Smart Solutions filing, Case 17-G-0606, Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customer Program, filed on September 29, 2017.

Portfolio Implementation

The Energy Efficiency and Demand Management ("EEDM") staff design, administer, and implement a portfolio of EE programs to deliver programs efficiently, cost effectively and successfully and to deliver savings to our customers.

In order for the Company to be appropriately staffed to achieve the proposed growth levels, and to support NWS efforts, the EEDM Department will need to increase its labor resources across a number of functions. In total, the Department is requesting thirty-six (36) incremental full-time employees or equivalents ("FTEs"). Additionally, the Department is transferring four (4) FTEs into O&M labor who are currently being charged to a capital program.

The 36 incremental employees, plus the 4 transferred FTEs, will perform the following functions:

i. 14 incremental employees will (i) expand and grow successful current programs that have additional potential for expansion; (ii) design, build and execute on newer and more innovative programs including through new delivery channels across customer segments, including efforts to (a) boost participation of LMI customers, (b) engage and manage relationships with our largest energy use customers who can commit to multi-year energy savings, (c) support sales with technical oversight and advisement from engineers, (d) make thoughtful and targeted interventions along the vertical supply chain, including the management of partnerships with retailers and distributors, and (e) develop initiatives that incentivize customer adoption of deeper EE measures such as HVAC and building envelope improvements; (iii) continue to develop new pilots to test emerging technologies, program delivery mechanisms and operational strategies that have the potential to become a meaningful contributor to a rapidly growing portfolio in the near to medium term; and (iv) provide technical resources to provide oversight to the management of the Technical Resources Manual ("TRM") to align the TRM with the growth and expansion of the EE portfolio.

ii. 6 incremental employees will (i) develop analyses of savings and helping achieve program optimization through the review of participation trends, market activity, and portfolio performance; (ii) manage the BCA process to determine that the programs are compliant with the State guidelines for cost-effectiveness; (iii) serve as data scientists responsible for evaluating market spending optimization and the integration of AMI data in analytics platforms, including research of new data sources, architecting data storage resources and maintaining data sources for continued accessibility and growth; (iv) assist with benchmarking efforts related to the maintenance of a web service interface as well as providing support to our customers associated with the Environmental Protection Agency ("EPA") Portfolio Manager so building owners may measure and track their energy consumption and emissions and comply with local laws; (v) create and support the Energy Efficiency Data Extract System to enable extraction of eligible customer information to determine eligibility to participate in the various programs covered by the EE and beneficial electrification portfolio; and (vi) importing data from other internal and external sources such as data from New York City databases, residential and commercial demographics data, and to merge that data with internal data for analytics purposes.

iii. 7 incremental employees will focus on managing the different budgets and process controls needed (i) to make strategic, operational and tactical decisions for the performance of the portfolio and (ii) to make decisions related to process optimization, process reviews and controls to check decisions are being made in accordance with internal rules and regulatory requirements. The group currently provides aggregation of financial and programmatic data, budget oversight and financial analysis and these positions will provide more detailed financial analytics and monitoring of all programs for real-time business insights and recommendations, and develop processes and controls to continuously improve internal processes and external reporting. In 2018, the team was responsible for managing a total of 36 budgets representing a total greater than $300 million with an expectation that it will grow in size, leading to an increased number of resources to manage the programmatic budgets to accurately be able to provide guidance for business decisions. Additionally, in order to help develop the appropriate controls that verify internal rules, financial requirements, and regulatory requirements are included in our processes, the group will require an additional resource responsible for data integrity and quality.

iv. 2 incremental employees will: (i) support NWS and other demand focused programs to manage the anticipated increase of capital deferral projects, as three to four possible additional projects are projected, (ii) manage the administration of EE adder programs that provide resources to boost EE adoption of the EE portfolio programs (such as Commercial Direct Install and Multi-Family) in NWS locations, and (iii) support development of program design and implementation, contractor oversight, technology engagement, contract negotiation, finance and budgeting, marketing, performance analysis, reporting, and for on-going process improvement. Additionally, the four (4) FTEs working on Targeted Demand Management being charged to the BQDM Program are moving to this operating function.

v. 6 incremental employees to: (i) develop additional capabilities in Evaluation, Measurement and Verification ("EM&V") to appropriately report on new programs that require updated or newer evaluation analyses to verify project savings and prevent reporting of overlaps, (ii) to ensure more robust EM&V processes are implemented, (iii) to increase efforts associated with (a) NWS projects that generally seek network peak reductions, (b) more complicated and deeper EE savings from new technologies, (c) managing growth in the EE portfolio generally, (d) developing appropriate advanced M&V techniques, and (e) expanding quality assurance and compliance.

vi. 1 incremental employee to (i) enhance Company efforts during the expansion of the EE portfolio through additional marketing communication to both support program awareness and track lead conversions and (ii) to focus on event coordination and development of marketing communication strategy.

Justification Summary:

Acceleration of EE is needed to achieve the State's policy objectives as identified in the NE:NY White Paper. The targets in NE:NY call for EE equivalent to 3% of investor owned utility sales by 2025. Acceleration of the ramp up is needed now to be on track for meeting this target. Achievement of these goals also provide benefits to customers through lower electric bills, health and wellness improvements and enhanced comfort and convenience, societal benefits, such as lower GHG and local emissions, increased innovation, enhanced market activity, local economic development, and reduction in wholesale capacity and energy needs. These goals also provide benefits to the Company's distribution system through "right-sizing" load cost-effectively first before consideration of infrastructure needs through the planning process.

Portfolio

The Company is proposing to spend $215.9 million, $257.8 million, and $300.3 million in the next three years (2020-2022) on its electric and gas EE and beneficial electrification portfolio of programs, not including any additionally authorized funds for gas EE approved as part of the NPS portfolio in the Smart Solutions proceeding. The Company will seek to achieve energy savings of 482 GWh, 562 GWh, and 640 GWh in the corresponding years and beneficial electrification goals of 115 MWh, 340 MWh and 550 MWh over the respective years. The Company will seek to generate gas energy savings of 620,000 Dth, 640,000 Dth, and 670,000 Dth in the corresponding rate years. Ramping electric EE savings from a level that is equivalent to approximately 1% of sales in 2019, the Company anticipates reaching 1.5% of sales in 2022. The Company anticipates achieving a unit cost of $0.37-$0.40/kWh through further optimization of program delivery and internal operations. The Company's proposed unit cost is meaningfully lower than the currently Commission approved levels of $0.43/kWh for Energy Efficiency Transition Implementation Plan ("ETIP") and around the range of the blended ETIP and EE Order unit costs of $0.36/kWh-$0.37/kWh reflected in the Company specific budgets and targets for achievements without and with low-to-moderate income ("LMI") customers represent significant improvements in cost efficiency, particularly considering countervailing upward cost pressures. The Company is also projecting a $62.4/Dth gas EE unit cost efficiency.

		2020		2021		2022	
Electric		**GWh**	**$M**	**GWh**	**$M**	**GWh**	**$M**
	Total	482	$178	562	$216	640	$254
	Unit Cost ($/kWh)	$0.37		$0.38		$0.40	
	% of Sales	1.1%		1.3%		1.5%	
Electri-fication		**MWh**	**$M**	**MWh**	**$M**	**MWh**	**$M**
	Total	115	$0.7	340	$2.6	550	$4.5
Gas[4]		**Dth**	**$M**	**Dth**	**$M**	**Dth**	**$M**
	Total	620,000	$37.2	640,000	$39.2	670,000	$41.8
	Unit Cost ($/Dth)	$60.0		$61.3		$62.4	
	% of Savings	0.36%		0.37%		0.39%	

Supplemental Information:

- Alternatives:
  Con Edison has determined that investing in EE is a critical part of our core business. An alternative to utility driven programs is EE adoption left solely to organic adoption in the marketplace, at the risk of not being able to achieve State and City goals.

- Risk of No Action or Delayed Action:
  No action would result in a business-as-usual scenario and risk a backsliding of State efforts to further grow EE and achieve ambitious targets while also resulting in the Company not using its longstanding experience and expertise in EE to help in the achievement of savings, and engage our customers positively.

  Further expansion of the programs increases net benefits to customers. Without the proposed expansion, the targeted benefits are less likely to be achieved.

- Non-financial Benefits:
  The EE portfolio provides enhanced customer satisfaction and aligns Company efforts with State policy goals. EE benefits customers by providing comfort and convenience, and through societal benefits, which include decreased GHG emissions, promotion of innovation, improved health and wellness, and stimulated economic development.

- Summary of Financial Benefits (if applicable) and Costs:
  EE and demand side management initiatives help offset future infrastructure spending, help participating customers save money on their utility bills, and achieve State and City policy targets of reducing emissions, which help to mitigate the societal cost of carbon and other GHG emissions.

[4] Gas targets and dollars do not include energy efficiency that may be approved under NPS

- Technical Evaluation/Analysis:
  A technical evaluation was completed using a potential study, peer benchmarking, historical performance, and other market data to model the trajectory of the growth of savings to be achieved and the corresponding costs.

- Project Relationships (if applicable):
  As EE becomes an integral part of system planning, there will be continued integration with DSIP, NWS, Demonstration projects, and other REV initiatives.

- Basis for Implementation Estimate:
  ` Implementation estimates are based on historical experience and anticipated future trends to extrapolate from a $/kWh and $/Dth per project category basis.

Annual Funding Levels ($000)

Historical Energy Efficiency Spend

Historical Elements of Expense

Electric EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Actual 2018**
Labor	**$1,939**	**$1,819**	**$2,064**			
M&S						
A/P	**$11,356**	**$17,989**	**$21,900**	**$36,552**		**$24,369**
Other	**$53,536**	**$36,637**	**$57,109**	**$61,346**		**$73,883**
AFUDC						
Total	**$66,831**	**$56,445**	**$81,074**	**$97,898**		**$98,252**

Gas EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Actual 2018**
Labor	**$560**	**$346**	**$503**			
M&S						
A/P	**$2,536**	**$3,771**	**$3,903**	**$4,748**		**$5,387**
Other	**$8,517**	**$6,197**	**$8,227**	**$5,605**		**$11,674**
AFUDC						
Total	**$11,614**	**$10,314**	**$12,634**	**$10,353**		**$17,061**

Notes:

- Reported expenses include EEPS II, ETIP, and Rate Case programs; with EEPS II and ETIP funded through surcharges and Rate Case programs funded as regulatory assets amortized over 10 years.
- In 2017, under the current rate period, all labor was transferred to base rates per the Commission Order Authorizing Utility – Administered Gas Energy Efficiency Portfolios for Implementation Beginning January 1, 2016.

Future Regulatory Asset Elements of Expense

EOE	2019	2020	2021	2022	2023
Labor					
M&S					
A/P	**$207,000**	**$215,900**	**$257,800**	**$300,300**	**$303,100**
Other					
AFUDC					
Overheads					
Total	**$207,000**	**$215,900**	**$257,800**	**$300,300**	**$303,100**

O&M

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	**$4,371**	**$4,776**	**$4,634**	**$9,247**	**$9,222**	**$9,445**
M&S	**$41**	**$16**	**$27**	**$53**	**$40**	**$36**
A/P						
Other	**$1,038**	**$704**	**$1,583**	**$1,255**	**$1,307**	**$1,382**
AFUDC						
Total	**$5,450**	**$5,496**	**$6,244**	**$10,555**	**$10,569**	**$10,863**

Future Elements of Expense

EOE	2019 Budgeted	2020	2021	2022	2023
Labor	**$11,917**	**$11,177**	**$12,407**	**$13,087**	**$13,487**
M&S	**$35**	**$42**	**$44**	**$46**	**$48**
A/P					
Other	**$1,087**	**$2,794**	**$2,932**	**$3,024**	**$3,099**
AFUDC					
Overheads					
Total	**$13,039**	**$14,013**	**$15,383**	**$16,157**	**$16,634**

X	Capital
	O&M

2020 – Customer Energy Solutions

Project/Program Title	Electric Vehicle Charging
Project Manager	John Shipman
Hyperion Project Number	PR.23317524
Status of Project	In-Progress / Engineering/Planning
Estimated Start Date	On going
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

Con Edison is proactively promoting increased Electric Vehicle ("EV") adoption. The Company has initiated demonstration projects and other programs which are in various stages of implementation to test market enablement strategies and promote EV readiness. The existing initiatives generally fall into three areas: (i) facilitation of charging infrastructure deployment, (ii) off-peak charging incentives and rate design, and (iii) Company and third party fleet initiatives. Additionally, Con Edison is a channel partner for EV and electric vehicle supply equipment ("EVSE") manufacturers. As a channel partner, the Company partners with the EV and EVSE market to sell the manufacturer's products, services, or technologies, including providing customers access to promotional rebates and offering Level 2 home charger units through the Company's Marketplace REV Demonstration Project. We are proposing two programs, one addressing the barriers to proliferation of charging infrastructure and the other to drive off-peak charging instead of charging during peak load hours.

Make Ready Interconnect Support: This program is designed to address a barrier to the installation of EV fast chargers. Through the program, the Company will install make-ready infrastructure for customers requesting the interconnection of publicly accessible fast chargers to facilitate EV penetration in Con Edison's territory on non-utility private properties that are not located in the public right-of-way. Make-ready infrastructure includes the additional service from the point of interconnection to the property line.

Currently, when customers or developers seek to install EV charging facilities that require a second service the charging facilities are characterized as excess distribution facilities ("EDF"). This means the interconnecting customer is solely responsible for the costs to extend the additional service to the charging station. This can be particularly problematic since parking locations are often distant from the site of building service. Given the dense urban environment of Con Edison's service territory, this can require extensive trenching and construction to extend the service, which translates to high EDF costs to the customer. As a result, EV developers will often submit multiple applications for a single project, with the intent to move forward only with the most cost-effective option, if at all. Furthermore, the high EDF costs may discourage customers from installing EVSE, which can be an obstacle to further EV penetration[1].

[1] Studies have found correlations between DCFC and EV sales. Mark Singer, Nat'l Renewable Energy Lab., *Consumer Views on Plug-in Electric Vehicles – National Benchmark Report* (Jan. 2016) pp. 18, 20; CalETC, *Evaluating Methods to Encourage Plug-in Electric Vehicle Adoption: A Review of Reports on PEV Incentive Effectiveness for California Utilities* p. 23. Prepared by Plug In America (Oct. 2016), *available at* https://pluginamerica.org/wp-content/uploads/2016/11/PEV-Incentive-Review-October-2016.pdf; Kansas City

This make-ready program proposes allocating capital funding to an annual program to install the EDF for qualifying customers. Customers would qualify by showing significant intent to move forward with the project (by installing their 'endline box') and by meeting the terms of the business incentive rate ("BIR"), which, among other terms, requires the EV charging facilities be accessible to the public. The program would be run similarly to Energy Efficiency programs where budgeted funds are allocated each year and qualifying applications in the queue are processed on a first-in, first-out basis.

The costs for this program will vary project to project, but the overall costs for the make-ready interconnect program work totals $30 million during 2020-2022. Based on historical experience, the EDF-related work for EV Direct Current Fast Charging ("DCFC") can vary from $700,000 to $2.5 million. In addition to the up-front costs, the EDF includes maintenance fees that can nearly double the cost to customers over ten years. With a median cost of approximately $900,000 for a station consisting of six 150 kW DCFC plugs, this program would enable approximately 10 MW of DCFC capacity and support approximately 21,450 additional EVs annually.[2] The timeline for the installation will vary.

<u>Off-Peak Charging Incentive:</u> In order to encourage off-peak charging to minimize adverse impacts of EV charging during peak load hours on the electrical system, Con Edison has implemented its SmartCharge NY ("SCNY") program. This program offers incentives to eligible EV drivers for charging in Con Edison's service territory at off-peak times and provides a $150 incentive for installing and activating a free connected car device from FleetCarma that allows users (and the Company) to know where, when, and how much energy an EV consumes during charge events.[3] Under the current program rules, participating customers receive $5 per month for keeping the device plugged in and charging in the Con Edison service territory, as well as earn $0.10 per kWh for charging between midnight and 8 a.m. on any day in the Con Edison service territory. During the summer (June 1 – September 30), customers receive an additional $20 when they avoid charging between 2:00 p.m. and 6:00 p.m. on weekdays. This technology and the data it collects can also help Con Edison understand charging behavior and EV driver response to incentives. The program costs include electronics that are placed in the customer vehicle and customer rebates for program participation.

For each charging session, the device records:

- Start date and time
- Duration of charging session
- Charging power level (kW)
- Total charging energy (total electricity consumed in kWh)
- 15-minute interval charging energy (kWh)
- Charging loss (electricity lost due to charging efficiency in kWh)
- Starting and ending state of charge
- GPS coordinates of where the charging session occurred

On September 12, 2018, the New York Public Service Commission approved the expansion of the SmartCharge program to include medium- and heavy-duty EVs, such as trucks and busses.[4] This

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Power and Light executives believe that an extensive investment in public charging eliminated range anxiety in its service territory and led to an increased adoption of EVs. See Garrett Fitzgerald and Chris Nelder. *From Gas to Grid: Building Charging Infrastructure to Power Electric Vehicle Demand. Rocky Mountain Institute* (2017) p. 31.

[2] Alternative Fuels Data Center. Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite. Accessed Nov 20, 2018 at https://afdc.energy.gov/evi-pro-lite

[3] EV owners do not need to be Con Edison customers in order to enroll in the SmartCharge New York program. Con Edison 2016 Electric Rate Case, Order Approving Electric and Gas Rate Plans (issued January 25, 2017), p. 39.

[4] Case 16-E-0060, <u>Proceeding as to the Motion as to the Rates, Charges, Rules and Regulations of</u>

expansion allows Con Edison to broaden opportunities to offset peak demand resulting in growth from this specific sector of the EV market. In the upcoming rate period, we plan to continue the SmartCharge program at higher funding levels to incent additional vehicles, including medium and heavy duty vehicles and buses. However, we will review the results of the program and determine if other off-peak charging incentives are available or provide greater customer response.

The off-peak charging incentive SCNY program costs will total $15 million across the three rate years, an increase of $9 million over the amount authorized in the current rate period, and will be recovered as a regulatory asset with a 10-year lifetime.

Justification Summary:

Recent forecasts suggest that there will be significant increases in EV sales and adoption in our territory in the coming years, in part due to New York's participation in the multi-state Zero Emissions Vehicle ("ZEV") Action Plan.[5] Within the state of New York, there are numerous policies and targets to encourage that growth. Widespread adoption of EVs provides an opportunity to utilities as a type of distributed energy resource, but also introduces challenges in terms of the potential impact on the grid and increased complexity to utility operations.

By facilitating the installation of additional publicly-accessible charging infrastructure through the make ready program, Con Edison can provide value in the EV value chain (through engineering and construction) in preparing for the forecasted growth in electric vehicles. This will support New York State's emissions reduction goal which calls for a 40% reduction in GHG emissions by 2030,[6] and its participation in the multi-state ZEV Action Plan.[7] This program is aligned with the EV Readiness Framework, where the Joint Utilities seek to "prudently invest utility customer funds in opportunities where the expected benefits resulting from increased sales outweigh the capital revenue requirements."[8]

Con Edison's dense urban service territory presents a unique challenge for deploying EV infrastructure. Public fast charging is viewed as a necessary component of the EV charging ecosystem for dense urban environments, as many vehicle owners do not have access to dedicated parking in driveways and rely on street or public charging. By taking a proactive approach to promoting and preparing for increased EV adoption, Con Edison is addressing stakeholder needs for EV charging infrastructure planning and development.

Consolidated Edison Company of New York, Inc. for Electric Service ("2016 Con Edison Electric Rate Proceeding"), Order Expanding Electric Vehicle Charging Program Eligibility (issued September 12, 2018).

[5] New York is one of nine states that has adopted the California ZEV regulations (see https://www.arb.ca.gov/msprog/zevprog/zevprog.htm) and is a signatory of the Multi-State ZEV Memorandum of Understanding which set a goal of 3.3 million ZEVs in the states by 2025. Based on the total number of cars in the states, New York's proportional share of ZEVs is approximately 800,000. The states are collaborating to remove barriers to EV adoption and EV charging infrastructure. *See* Zero Emission Vehicle Program, Memorandum of Understanding (executed on Oct. 24, 2013), *available at* http://www.nescaum.org/documents/zev-mou-9-governors-signed-20180503.pdf/

[6] Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Adopting a Clean Energy Standard, issued August 1, 2016.

[7] New York is one of nine states that has adopted the California ZEV regulations (see https://www.arb.ca.gov/msprog/zevprog/zevprog.htm) and is a signatory of the Multi-State ZEV Memorandum of Understanding which set a goal of 3.3 million ZEVs in the states by 2025. Based on the total number of cars in the states, New York's proportional share of ZEVs is approximately 800,000. The states are collaborating to remove barriers to EV adoption and EV charging infrastructure. *See* Zero Emission Vehicle Program, Memorandum of Understanding (executed on Oct. 24, 2013), *available at* http://www.nescaum.org/documents/zev-mou-9-governors-signed-20180503.pdf/

[8] Joint Utilities of New York, Electric Vehicle Readiness Framework Final Draft, March 2018, *available at* https://jointutilitiesofny.org/wp-content/uploads/2018/03/Joint-Utilities-of-New-York-EV-Readiness-Framework-Final-Draft-March-2018.pdf

The make-ready infrastructure program will also improve the efficiency with which Con Edison engineers are able to respond to customer EV interconnection requests. Currently, some EV developers submit multiple applications for a single project in order to compare EDF charges. For instance, for an EVSE project in 2017, a developer submitted fifteen projects for rulings and only moved forward with one project.

The SCNY program encourages off-peak charging, which can help to mitigate the grid impacts of new EV charging loads and customers' exposure to higher charging costs. As more EV DCFCs are connected to the system, in part supported by the make-ready infrastructure program, incentivizing off-peak EV charging within Con Edison's service territory will become even more important. The program will also help Con Edison understand charging behavior and EV driver response to incentives, allowing for program improvements. Additionally, the expansion of the SCNY program extends encouragement of off-peak charging to medium- and heavy-duty vehicle classes as additional types of electric vehicles are being introduced in the Company's service territory. For example, the Metropolitan Transportation Authority is operating a pilot program using 10 electric buses on routes in Manhattan and Brooklyn/Queens. Also, the Company understands that medium-duty electric trucks are being produced and are beginning to operate on New York City's roads.

Supplemental Information:

- Alternatives:
  Alternatives considered for these programs include installing EV charging equipment to stimulate EV penetration. Ultimately, Con Edison has decided against this approach because the Company can more effectively add to the EVSE value chain by leveraging engineering and construction strengths to design and install the infrastructure between the charger and the grid. Additionally, the Company's service territory has been targeted by several EVSE developers for infrastructure projects due to the anticipated higher levels of EV adoption compared to other territories in the state.

- Risk of No Action:
  Taking no action for these programs would maintain the status quo for EV infrastructure interconnection and rate design, ignoring the role the utility can play in developing beneficial electrification. Based on current forecasts, despite robust EV growth, the status quo approach would fall short of meeting EV policy goals.

  Not continuing and expanding the SmartCharge program may result in adverse grid impacts due to charging during peak periods.

- Non-financial Benefits:
  The non-financial benefits of these programs are increased customer satisfaction for those who own EVs (expected to be 155,000 by 2025) or develop projects for EV infrastructure. By enabling the fuel conversion of vehicles from combustion engines to electric vehicles, GHG and sulfur and nitrogen oxide ("SOx" and "NOx") emissions will be reduced. The continuation and expansion of the SmartCharge program will help to minimize the impact of increased EV charging on electrical infrastructure during peak periods.

- Summary of Financial Benefits (if applicable) and Costs:
  The Societal Cost Test ("SCT") is a measure of cost effectiveness in the Benefit Cost Analysis framework which is used for assessing the value of other utility programs such as the non-wires solutions efforts. The SCT results for the make-ready infrastructure project are positive and include benefits such as avoided CO_2 emissions and reductions in peak customer load.

- Technical Evaluation/Analysis:
  In support of expanding the scope of its BIR to include electric vehicle quick charging, Con Edison performed a financial analysis to explore customer savings under multiple rate structure scenarios. The resultant rate structure that was approved in April 2018 makes it more attractive for business owners to install EV charging equipment. The make-ready infrastructure program will further strengthen the business case for business owners looking to install this charging equipment.

  The SCNY program offers an innovative approach to providing customer value outside of technology specific rates. Experience under the current SmartCharge program has shown that customers have embraced this approach at a much higher adoption level than the dedicated or whole-house EV rates offered to EV owners.

- Project Relationships (if applicable):
  State and other policy goals

- Basis for Estimate:
  Project costs for the make-ready infrastructure were estimated using historical cost data for similar projects. Project costs for an expanded SmartCharge were based on the costs of the current program.

Annual Funding Levels ($000):

Regulatory Asset:

Historic Elements of Expense

EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Forecast 2018**
Labor						
M&S				11		3
A/P				829		778
Other				19		36
Overheads						
Total				**859**		**817**

Future Elements of Expense:

EOE	**Budget 2019**	**Request 2020**	**Request 2021**	**Request 2022**	**Request 2023**
Labor					
M&S	5	12	18	32	
A/P	588	1564	2451	4237	
Other	482	1283	2009	3474	
Overheads					
Total	**1,075**	**2,859**	**4,478**	**7,743**	**N/A**

Capital:

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P						
Other						
Overheads						
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	

Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor		425	432	434	533
M&S		2,016	2,056	2,026	2,426
A/P	**N/A**	3,910	4,014	3,945	4,769
Other		724	739	724	876
Overheads		2,925	2,759	2,871	3,396
Total		**10,000**	**10,000**	**10,000**	**12,000**

X	Capital
X	O&M

2020 – Customer Energy Solutions

Project/Program Title	Utility Energy Storage
Project Manager	Mohamed Kamaludeen
Hyperion Project Number	PR.23322939
Status of Project	Initiation
Estimated Start Date	01/2020
Estimated Completion Date	12/2022
Work Plan Category	Strategic

Work Description:

The Company recognizes that energy storage technology, which will be referred to as "energy storage", "storage" or "battery(ies)" interchangeably throughout this whitepaper, may have the potential to provide significant societal and operational value to the grid through multiple value streams, not all of which might currently be monetized under the existing regulatory or financial constructs. Following the recent *Order Establishing Energy Storage Goal and Deployment Policy*[1] which established a goal of deployment of 1,500 MWs of storage in New York State by 2025, the Company proposes to convert multiple carefully selected plots of Company land into energy storage facilities. The Company proposes to design, build, own and operate six Company-owned energy storage facilities to provide distribution grid support, develop key Company competencies around storage, and evaluate the beneficial uses of such equipment for the distribution system. Per the Reforming the Energy Vision ("REV") Track 1 Order,[2] the New York State Public Service Commission ("PSC") permits utility ownership of energy storage projects that integrate storage into distribution system architecture.

The six proposed energy storage installations will contribute a total of 31.5 MW/120 MWh peak demand reduction, be fully-integrated into the Company's distribution system infrastructure and eventually, into the core Distributed System Platform operations. The systems will be located in areas experiencing high growth, high penetration of intermittent resources or constraints in operational capability requiring load relief. During 2020-2022, the total capital cost is $90.5 million, and the total O&M costs are $15.5 million.

After a comprehensive review of potential Company-owned sites, six sites were selected to address the following three diverse electric distribution reliability use cases across three regions:

1. Manage the growing load which is non-coincident with the system peak in the Company's Brooklyn and Queens load pockets and apply the learnings for future planning purposes.

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[1] Case 18-E-0130, In the Matter of Energy Storage Deployment Program, Order Establishing Energy Storage Goal and Deployment Policy, issued December 13, 2018.
[2] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan, filed February 26, 2015.

2. Mitigate the use of standby diesel-powered mobile generators for summer contingency plans in Staten Island at two different sites and therefore reduce the environmental impact as well as the Company's operational expense.
3. Smooth the rapid and steep changes in hourly aggregate energy load at two sites in Westchester County that have a significant saturation of rooftop solar photovoltaic panels thereby improving overall distribution asset utilization and minimizing the thermal stress on the Company's distribution equipment due to such load patterns.

The Company will develop the six sites into "energy storage docking stations" with standardized interconnection infrastructure so that containerized energy storage equipment can easily connect to the distribution system. Since these energy storage systems are designed to enhance electric distribution reliability and are installed on Company sites which also contain critical infrastructure, Con Edison proposes to own and operate the equipment. The Company will issue competitive solicitations allowing battery developers to submit proposals to design, implement, and commission the battery systems. These system-integrated assets would be treated comparably to traditional infrastructure assets for which the Company is seeking to recover all development and implementation costs of the energy storage system as a Company-owned asset.

Ongoing maintenance and operation of these batteries will include service contracts with vendors as well as employee time for inspections, operations and oversight. The organizational needs and approach towards the ongoing inspection, maintenance and operations of these energy storage systems are as follows:

1. Inspections and preventive maintenance: For the six sites, substation operations will be responsible for the minor maintenance, inspections, and overall health of the energy storage system. Inspections of the energy storage system components range from monthly to annually and include general inspection, outdoor gear, switch gear, transformers, protective relays, and fire alarms and suppression system etc. The Company estimates that 0.20 full time equivalent ("FTE") will be required to perform this work at the six sites.
2. Operations: Utility Scale Energy Storage devices pose unique and new challenges to the Company as they require collaboration between multiple organizations for safe and reliable operations. Operational jurisdiction and control will be shared between Electric Operations and the Substations group in Central Engineering. Switching during contingencies, inspections, and overall monitoring of the facilities will be done by Company personnel. We estimate 0.20 FTE for these tasks.
3. Data Collection and Communication: Where required, the project design will specify installation of utility-grade watt-hour meters or other measurement devices, as listed in the most current version of the PSC Approved Meter List and as prescribed in the PSC's Utility Metering Operating Manual (16 NYCRR Part 92). The meters will be equipped with communications ports that will allow direct, real-time connection to Con Edison's systems. Inspection and overall maintenance of these meters will be done by Company personnel. We estimate 0.10 FTE for these tasks.
4. Training: Development of a skilled labor force is required internally (at both union and management levels) and externally with various stakeholders including the Fire Department of New York, New York City Departments of Environmental Protection and Buildings, and the Department of Central Planning, and municipal authorities in Westchester. The Company will need to develop the appropriate specifications, procedures and training courses. Con Edison estimates 0.5 FTE for these tasks.

In summary, the Company is estimating the equivalent of one (1) FTE employee in total to perform ongoing inspection, maintenance, operations, and training for the six energy storage systems.

Justification:

The Company is investigating the feasibility and usefulness of battery installations throughout the service territory at various utility-owned sites. A comprehensive inventory of Company owned properties was completed to determine the feasibility of the utility developing and installing batteries in the near term and to satisfy future system needs. Potential locations, following the criteria described below, were shortlisted through a bottom-up survey of Company properties that might be conducive for installing batteries. A team of Company experts visited each shortlisted location to determine the feasibility of siting the battery containers and how many containers can be placed on these sites based on physical size restrictions with the understanding that further detailed construction review of each location will be required before final determination.

The team's primary focus was situating the batteries on the utility substation properties with available land for battery installations. Larger size installations, as compared to smaller size installations on space-constrained sites, will lower unit cost of the overall storage installation through economies of scale. Lithium ion battery technology was assumed as the basis of design for determining the storage capacity that could be installed at each site, however other suitable technologies that meet Company needs will be considered. Lithium ion batteries are commercially available, satisfy load relief and reliability needs and have been successfully installed at Company and customer properties in our territory. For example, the Company purchased a 2 MW/12 MWh lithium ion storage system which was installed on a Company property as part of the Brooklyn Queens Demand Management ("BQDM") program under which it now serves as a fundamental asset in a portfolio of solutions enabling the deferral of a new substation.

Con Edison built upon lessons learned from the utility owned BQDM battery project to develop the site evaluation criteria described below. The Company will continue to evolve and expand the criteria for installing energy storage based on additional lessons learned to further meet the State public policy goals. The criteria used include:

1. "Available land" at Transmission, Area and Unit Substations with topology conducive to installation of batteries,
2. Substations which require load relief and/or operational measures to satisfy design criteria,
3. Substations which become constrained during distribution contingencies,
4. Networks/load areas in which five-year compounded growth rate of load is 3% or higher, and
5. Networks in which periods of more rapid evening load ramps occur due to localized solar distributed generation, referred to as 'duck curves.'[3]

The six locations selected, which are dispersed across three operating regions addressing these three distinct use cases, will enable the Company to broaden its expertise in future deployments. Locations and benefits are summarized below and not ranked in any specific order of deployment:

1. Brooklyn/Queens:

[3] http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf; accessed July 25, 2018.

A. Richmond Hill Network: Eight containers of energy storage will be installed at a unit substation in this network. The battery will discharge over a peak period of two hours at an output of 6 MW/12 MWh. This location, the initial BQDM site, can potentially replace or supplement the operational measures currently used for load relief in the Brownsville load pocket.
B. Long Island City: This network has experienced rapid residential development of the waterfront neighborhoods leading to a five-year average load growth rate which is non-coincident with the system peak and well above the average growth rate of any other load area in the Company's service territory. To address the needs of such rapid growth, the Company plans to install 8 containers of energy storage at an area substation. The battery will discharge over a peak period of four hours at an output of 3 MW/12 MWh.

2. Staten Island:
   A. Fresh Kills: 24 containers of energy storage will be installed at an area substation in this load area. The battery will discharge over a peak period of four hours at an output of 9 MW/36 MWh. This storage system can potentially replace or defer traditional load relief within the planning horizon and offers an ideal platform to train employees to engineer and operate energy storage at multiple voltage classes.[4]
   B. Foxhills: 20 containers of energy storage will be installed at a site, designated for future use, in this load area. The battery will discharge over a peak period of three hours at an output of 7.5 MW/30 MWh. It will provide relief during system contingencies associated with three other distribution substations and corresponding networks/load areas during high load days. The Company will have the flexibility to adjust the mode of operations to match system conditions which could limit the number of diesel-generators which are deployed in the event of distribution system contingencies. Furthermore, these assets will provide voltage support and quick ramp up of load for areas in which there is a high penetration of intermittent solar and associated rapid evening ramp of load.

3. Westchester:
   A. New Rochelle: Eight containers of energy storage will be installed at a utility-owned site in this load area. The battery will discharge over a peak period of five hours at an output of 2.4 MW/12 MWh. This installation will reduce the peak loading on distribution equipment, thereby extending equipment life and potentially reducing costs.
   B. Millwood West: 12 containers of energy storage will be installed at a utility-owned site at this Company facility. The battery will discharge over a peak period of five hours at an output of 3.6 MW/18 MWh. This installation will minimize the need for operational measures, such as voltage reductions or increases under contingencies. Reducing the peak load could extend equipment life and reduce operational and capital costs associated with failures and maintenance.

The achievable MW/MWh values will vary as a function of the discharge period (that is, if the discharge period is outside the network peak hour used in the estimate). The most suitable discharge period will be determined during the engineering study and vetted against any operational restrictions identified during testing. Furthermore, if any of these locations pose significant challenges to the installation of energy storage, a more suitable alternate location with be pursued.

[4] Depending on the interconnection studies, the Company can connect to the 4kV, 13kV, 33kV, 138kV or 345kV feeders.

Construction and remediation at the sites will start in 2020 at Richmond Hill, Fox Hills and Millwood and in 2021, at Long Island City, Fresh Kills, and New Rochelle. We expect that all systems will be fully operational by 2025 at the latest. A more detailed deployment schedule cannot be provided at this time due to uncertainties in the remediation activities required and the local permitting process and requirements across the different city and municipal agencies, both of which can significantly impact project schedules.

Supplemental Information:

- Alternatives: The alternative to this approach would be the installation of customer sited energy storage systems or utility owned and operated systems on third-party owned-land which the Company would lease. However, with the large footprint required by batteries and the space constraints in the greater New York City area, these approaches may not best support the State in achieving its storage goals in the prescribed timeframe.

- Risk of No Action: No action would:
  Delay system benefits, learnings, and development of Company competencies from this technology.

- Non-financial Benefits: Implementation of energy storage systems at the six sites will provide the following benefits:
  - Support the achievement of state energy storage goals through installation of storage capacity as well as through supporting the development of the state storage market by providing shovel ready project opportunities for developers.
  - Develop key energy storage competencies in the Company around procurement, development and operation of storage assets.
  - Leverage near-term benefits of storage while also building experience and understanding around how storage can meet diverse future distribution system needs.

- Summary of Financial Benefits (if applicable) and Costs: It is expected that installation of energy storage equipment on the distribution system will result in benefits to our customers through deferral of traditional investments as well as potential avoided generation and transmission costs while the costs of energy storage systems decrease over time.

- Technical Evaluation/Analysis: The Company experience with the procurement and installation of the BQDM utility-owned battery installation provides many financial and technical insights in site evaluation and cost estimation.

- Project Relationships (if applicable):
  - Distribution System Implementation Plan ("DSIP") – The Company filed its second DSIP in July 2018,[5] promoting the goals of the REV initiative and the PSC's vision of a robust market for distributed energy resources that increases customer choice and promotes a sustainable energy future. The DSIP describes the Company's energy storage related efforts and notes

[5] Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Second Distributed System Implementation Plan, filed July 31, 2018.

that Con Edison will explore "adding energy storage resources where and how they can best benefit the system and customers."

  - Non-Wires Solutions ("NWS") – NWS are implemented to meet specific reliability needs that have been identified in the distribution planning process, typically on customer properties.
  - REV Demonstration Projects – Demonstration Projects are designed with the goal of testing new business models and providing novel services to customers. The Company has developed three energy storage Demonstration Projects which explore energy storage technologies and new business models these technologies enable.

- Basis for Estimate:
  Estimation for the storage capital cost was completed using Lazard's Levelized Cost of Storage ("LCOS") study[6] to estimate the costs of the major components of the storage systems. Storage module costs include the racking frame, battery management system, and battery modules. Balance of system costs include the storage container, monitoring and control electronics, thermal management, and fire suppression systems. The power conversion system costs include the inverter, protection, and energy management system. Engineering, procurement, and construction costs include project management, engineering studies, site preparation and construction, foundation/mounting, and commissioning, with an adder for the elevated labor, logistics and other costs in the New York region.

  The O&M implementation and maintenance costs are based on the Lazard LCOS and adjusted to reflect NYC conditions. Types of activities include minor repairs, basic parts and hardware and standard preventative maintenance. Also included in these estimates are the more significant remediation costs for each site based on initial inspections and a projection of the associated labor cost. Consequently, the O&M cost during 2020 is significantly higher than the later years in the rate period since it is expected that the majority of the remediation work will occur during this year.

  In the funding tables below the Company assumes an annual cash-flow schedule reflective of the BQDM project actual spending schedule.

[6] Lazard's levelized cost of storage ("LCOS") study, version 3.0; Lazard Ltd. November 2017; https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf; accessed October 29, 2018

Annual Funding Levels ($000):

Capital

Historical Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P						
Other						
Overheads						
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

Future Elements of Expense ($000):

EOE	Budget 2019	Budget 2020	Budget 2021	Budget 2022	Budget 2023
Labor		$4,613	$4,782	$6,210	$7,763
M&S					
A/P		$8,508	$10,239	$44,256	$55,320
Other					
Overheads		$879	$1,480	$9,534	$11,917
Total		**$14,000**	**$16,501**	**$60,000**	**$75,000**

O&M

Historical Elements of Expense:

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P						
Other						
Overheads						
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

Future Elements of Expense:

EOE	Budget 2019	Budget 2020	Budget 2021	Budget 2022	Budget 2023
Labor		$1,119	$1,179	$1,412	$1,452
M&S					
A/P					
Other		$11,749	$0	$0	$0
AFUDC					
Overheads					
Total		**$12,868**	**$1,179**	**$1,412**	**$1,452**

X	Capital
X	O&M

2020 – Customer Energy Solutions

Project/Program Title	Distributed System Platform ("DSP")
Project Manager	Steven Malena
Hyperion Project Number	PR.21151526
Status of Project	In-Progress
Estimated Start Date	1/2017
Estimated Completion Date	12/2022
Work Plan Category	Regulatory Required

Work Description:

As part of New York State's Reforming the Energy Vision ("REV"), the Company continues to develop the DSP to better integrate customer and utility owned distributed energy resources ("DER") into the grid of the future. Establishing a DSP is a cornerstone of the REV proceeding. Since the Track One Order,[1] Con Edison has advanced in developing its people, processes, and technologies as a DSP. DSP-related accomplishments include:

- Implementing the Interconnection Online Application Portal ("IOAP"), leveraging the PowerClerk tool to streamline the interconnection process,
- Implementing hosting capacity maps for both non-network and network system designs,
- Implementing the "Green Button Connect – My data" application allowing customers to share their energy usage data with authorized third parties,
- Formalizing the identification and evaluation of non-wires solutions (NWS) as part of the capital planning process and delivering over 160 MW of NWS opportunities to DER providers,
- Publishing a system data portal website which directs third parties to Con Edison's hosting capacity maps, 8760 load forecasts and queued and installed distributed generation ("DG") at different points on the grid,
- Installation of modernized network protector ("NWP") relays that facilitate DER interconnection and export to the grid, enhance fault isolation, and increase operational flexibility,
- Installation of Volt-VAR Optimization ("VVO") controllers and communicating modems at 4kV unit substations,
- Scoping and implementation of a new Demand Response Management System ("DRMS") that will run in parallel with the existing DRMS through the 2019 Demand Response ("DR") season to allow time for the new system to be fully tested in a live environment,
- Implementation of several programs on the Demand Management Tracking System ("DMTS") (Commercial & Industrial, Multi-family, residential), applying DMTS to maintain and update the Brooklyn Queens Demand Management ("BQDM") program, and developing and stabilizing interfaces between DMTS and other systems,

[1] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan ("Track One Order"), issued February 26, 2015.

- Implementation of a web-services interface with the Environmental Protection Agency ("EPA") portfolio manager so building owners may easily comply with Local Law 84 ("LL84"), as well as measure and track their energy consumption and greenhouse gas emissions, and
- Demand management use cases developed and data integrated to the Enterprise Data Analytics Platform ("EDAP").

These achievements provide a solid foundation for continued momentum for implementing the Company's Distributed System Implementation Plan ("DSIP").[2] The next steps and future actions summarized below are consistent with the long-term vision of the Company to enable market services, integrate DER, and support information sharing with DER developers. These are described as the three core services of the DSP, shown and described below:

- **DER integration** refers to planning and operational enhancements that promote faster integration of more DER, with enhanced safety and reliability.
- **Information sharing** refers to information technology ("IT") enhancements that enable customer choice and participation of third-party vendors and aggregators in markets for distributed resources.
- **Market services** refers to enhanced pricing, programs, and procurement that help achieve DER value through market mechanisms.

The investments for DSP development are grouped and discussed using this framework:

1) DER Integration

There are two key elements for DSP DER integration services, interconnection and operations. For interconnection, the goal is for safe, secure, and timely interconnection to the distribution system for DG and energy storage. Operationally, the goal is for safe and reliable operation of the distribution system as more DG, energy storage, electric vehicles, and electric heating loads connect to the system. With the growth of small, residential solar, Con Edison receives thousands of applications per year. The

[2] Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Second Distributed System Implementation Plan ("2018 DSIP filing"), (filed July 31, 2018).

enhancements to the IOAP and hosting capacity maps meet the needs of developers requesting interconnection.

a. VVO: VVO is a set of voltage management capabilities, which includes both Conservation Voltage Optimization ("CVO") and reactive power management. The primary purpose of VVO is to maintain acceptable voltage at all points along the distribution feeder under all loading conditions. Currently, voltage is measured and controlled at the substation according to a voltage schedule. There are instances where voltage is higher at the beginning of a feeder closest to the substation and is lower toward the "grid edge" or end of the feeder. Voltage can be more efficiently managed through greater system visibility, more fine-tuned controls, and by controlling voltage levels dynamically along the entire length of the feeder.

Optimally managing system voltage levels increases system efficiency by regulating the voltage to adequately serve the grid edge, while not oversupplying the points nearer to the substations. This provides greenhouse gas reductions, customer savings, and allows for greater penetration of DER on the system. VVO benefits are related to energy savings provided by CVO identified in the Company's Advanced Meter Infrastructure ("AMI") business plan.[3] The CVO benefits from AMI target a 1.5 percent aggregate energy savings; however, in local pockets taking action on the AMI data is not possible without the SCADA monitoring and metering equipment installed through this initiative. The Company will achieve these benefits by building off the investments that are already underway and deploying additional voltage control devices, monitoring equipment, communications, and systems interfaces.

The Company has begun investing in capabilities to more dynamically manage voltage at different levels of the distribution system. First, voltage management capabilities are greatly enhanced with the AMI implementation, as operators will have more granular and frequently updated voltage data from the grid edge. Also, the Company has begun installing VVO controllers and communicating modems at 4kV unit substations and expects to complete that by the end of 2019.

The Company foresees VVO capabilities developing in phases, with each phase becoming more dynamic and distributed:

- The first phase involves setting more efficient static voltage schedules by analyzing the AMI voltage information.
- The next phase involves dynamic centralized voltage control based on real-time AMI and sensor data.
- The final phase extends to distributed voltage control which may potentially include leveraging DERs and smart inverters for reactive power support.

The VVO investment for 2020 to 2022 focuses on the equipment needed to enable the first phase of VVO capabilities. These include equipment in the area substations and IT systems to interface with Meter Data Management System in order to act upon the greater granularity of data from AMI. Specifically:

[3] Case 15-E-0050, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Con Edison Advanced Metering Infrastructure Business Plan ("AMI Business Plan"), filed November 16, 2015.

- Area station metering: Area substation meters monitor the voltage and current at the area substation bus so that voltage within specifications is delivered to customers. Most of the existing meters are nearly forty years old. This program targets the substation meters at substations built before 1980 for replacement to provide more granular voltage measurements for VVO. 41 area substations fall within the population that were built prior to 1980, and metering upgrades will prioritize low accuracy transducers and other single element metering elements. Upgrading the substation metering is necessary to enable the more granular VVO use cases.
- Instrument transformer upgrades: Equipment, such as potential transformer and current transformer replacements, that support metering and voltage regulation, is targeted to provide accurate input to meters and a reliable, granular VVO system. This enhancement is also needed to verify the energy savings that are achieved through AMI-enabled VVO capabilities.
- Vintage Remote Terminal Units ("RTUs"): RTUs that affect the station's ability to maintain remote voltage control or metering will be targeted for replacement. A small population of RTUs that commonly affect remote communication and the control of tap changers have been identified.
- Non-network distribution system pole top regulator upgrades, which will provide more precise voltage regulation, as well as remote monitoring and control capabilities.
- Additional communications and control upgrades will be needed to support some of these replacements with costs varying based on the specific area substation.

Approximately 17 area substations will receive Contact Making Volt Meter replacements at an estimated cost of $500,000 per substation. In addition, up to 41 of the area substations with older metering, as described above, will receive metering replacements at an estimated cost of $500,000 per substation. Three RTUs have also been identified for replacement at an estimated cost off $1 million per RTU.

This investment is incremental to, and dependent on, the AMI buildout and the deployment of this functionality will geographically coincide with the AMI rollout. Area station equipment upgrades will target the lowest performing parts of the total voltage regulation system, as measured by historical data on past ability to maintain remote control or regulate within a target.

b. Modernize NWP Relays: Most NWPs are currently equipped with a non-communicating microprocessor relay ("MPR"). Non-communicating MPRs are designed to identify when a reverse power flow condition exists, such as when DG provides power to the grid, and automatically trips the associated NWP. When a NWP does not trip the feeder remains alive-on-backfeed ("ABF"). Depending on system conditions, a feeder can remain ABF anywhere from a few cycles to hours. Troubleshooting ABF conditions delays feeder processing. In addition, ABF conditions that follow a single line-to-ground fault can cause the voltage on the unfaulted phases to increase by as much as 73 percent. The Company's internal analysis has shown that there is a correlation between this rise in voltage and faults on the unfaulted phases, known as second faults. As DER penetration increases, there will be more persistent challenges.

A modernized MPR is capable of two-way wireless communication via an external modem. This additional communication capability will allow for supervisory control and data acquisition ("SCADA"), which will provide control centers functionality for monitoring and fault isolation, soft-transfer trips, and DER integration enablement. This provides several benefits, allowing the Company to:

- Increase available hosting capacity, enable lower cost interconnections, and allow DG customers to back-feed more energy to the system without impacting system reliability,
- Maintain operator visibility to NWP status during a backfeed condition which enables faster ABF cause identification and feeder processing,
- Reduce second faults by improving feeder processing time,
- Enable soft transfer trips, which de-energize the ABF on feeders to protect both customers and utility equipment. Soft transfer trips are automatic and operate in near real-time, and
- Load and de-load feeders remotely without sending a work crew to manually open the NWP.

This investment continues and scales up the installations started in 2017. To date, the Company has installed approximately 500 modernized NWPs (30 with SCADA capabilities), and projects the installation of an additional 400 by the end of 2019. Between 2020 and 2022, the Company will accelerate the deployment to an annual rate of 600 relay upgrades, 200 of which will have SCADA capabilities.

This investment includes the costs associated with the relay upgrade as well as the enhancement to back-end IT systems that will use the SCADA data to provide the proper level of visualization and situational awareness to operators. In parallel, to increase the SCADA-capable NWPs, the Company is testing the performance of the AMI network for SCADA operations. In the long term, successful testing of the AMI network and sufficient IT SCADA systems capacity could enable the Company to scale the SCADA capabilities across all 27,000+ NWPs.

The locations for relay upgrades are selected by prioritizing areas where DER penetration is greatest or infrastructure capability most constrained. By taking this approach, the Company improves its capabilities in areas where there is high DER potential or where it is beneficial for DER to interconnect. This approach maintains system reliability and resiliency while allowing for the integration of more DER into the electric system.

c. **IOAP/Hosting Capacity:** Con Edison maintains an IOAP to facilitate timely DER interconnection processes (www.coned.com/dg), which now leverages the PowerClerk tool as well as enhancements to its case management tool, the Customer Project Management System. The IOAP design includes elements of the Electric Power Research Institute IOAP evaluation and phased approach, of which, Con Edison completed Phase 1 in October 2017. These changes offered more granularity and transparency to the customer during the Standardized Interconnection Requirements process and automated many of the screens, data exchanges and processing steps that increased transparency in application processing. Phase 2 requirements to create base functionality in Con Edison's core systems that will facilitate future enhancements will be complete by the end of 2019. This includes providing DER hosting capacity (designed to identify areas in the distribution system where DER can most readily connect to the system).

Further investment to the IOAP and hosting capacity maps between 2020 and 2022 is required to enhance the functionality of the hosting capacity portal to increase the refresh frequency of hosting capacity analysis and explore additional use cases for hosting capacity. Con Edison is committed to continuing conversations with stakeholders to explore additional enhancements that may include forecasted hosting capacity, operational flexibility analysis, and the incorporation of additional technologies (energy storage, electric vehicles) into the hosting capacity analysis. Con Edison will further integrate load flow analysis with our hosting capacity portal within the interconnection process, provide an online payment option for developers, integrate the IOAP to the DER Management System ("DERMS") and Geographic Information System ("GIS") for visualization of queued and connected DER. These enhancements will provide several benefits to customers and developers such as:

- An enhanced customer experience,
- More accurate DER data and visualization, and
- Timelier interconnection application processing.

2) <u>Market Services</u>

The goals for DSP market service functionality are procurement, optimization, settlement, and billing. The procurement goal is to make cost-effective investments in distribution capability through procurement of non-wires service and, further future state distribution level services. The longer-term optimization, settlement, and billing goals are seamless real-time co-optimization of wholesale and distribution market value.

a. DERMS: DERMS is an advanced software application that performs a number of DER-related functions, including DER asset management, planning, forecasting, and in the longer term, monitoring and dispatch. The conceptual purpose of a DERMS is to manage diverse DER, to understand the unique status and capabilities of each, and present these capabilities to a Distribution Management System and other applications in a more useful and manageable way. With a better understanding of the status and capabilities of DER on the system, Con Edison will be able to better manage an increasingly complex and bi-directional electric system.

Con Edison has taken several steps to begin implementing its DERMS. In 2017, Con Edison benchmarked current and future state DERMS solutions of four peer utilities in order to inform specific use cases that would guide internal DERMS development over a five-year investment window. In addition, the Company also invited several top tier vendors to showcase their DERMS solutions. The benchmarking and vendor showcases indicated there were no available Commercial-off-the-Shelf (COTS) products suitable for Con Edison's network design, and that a COTS product would not be available for several years. It also informed the initial investment decisions for Con Edison's DERMS by surfacing use cases and requirements that will be necessary for its DERMS. The Company used those requirements to conduct a fit gap assessment in 2017. The fit gap assessment identified four phases of DERMS functionality:

i. DER Asset Management
ii. DER Planning and Forecasting
iii. DER Monitoring and Dispatch
iv. DER Markets and Settlement

Efforts to date have focused on phases 1 and 2 by integrating planning functions (both near- and long-term) with DER data capabilities into a DERMS environment. Enhancements have been made that link the IOAP to the existing DG database allowing for easier updates to DG-inclusive modeling that will facilitate future DERMS functionality as well as Stage 3 Hosting Capacity goals, as defined in the Company's 2018 DSIP filing. In 2019, Con Edison plans to pilot DERMS functionality around all four phases in order to further inform a longer term vision that will define the elements of software and monitoring and control infrastructure that will be needed to enable an operational DERMS.

The DERMS has leveraged other investments made between 2016 and 2018, such as the Customer Portal and IOAP projects. DERMS will also leverage the GIS which is seen as a foundational element to provide the utility with the ability to accurately locate and model the various DER attributes in a single system of record that can be exported for load flow and optimization.

Between 2020 and 2022, the Company will implement phase 2 capabilities by integrating load flow analysis and will continue to pilot phase 3 monitoring and dispatch capabilities with new software tools. The DERMS investment includes the software as well as communications, monitoring, and control infrastructure that will be vital to the real-time facilitation of an operational DERMS. The functionality gained, in addition to the lessons learned from these efforts, will set the stage for market optimization/dispatch work that will commence thereafter, as later phases of the DERMS solution are achieved and as market rules mature.

b. DMTS: Con Edison placed DMTS in production in 2014, and, in 2016, further enhanced DMTS. DMTS provides the Company with the necessary technology infrastructure to track and manage the performance of the Company's energy efficiency and demand management ("EEDM") portfolio goals. Since 2016, the EEDM Department has completed implementation of a number of existing programs into DMTS (e.g., Commercial & Industrial, Multi-family, residential), including BQDM, and developed and stabilized the interfaces between DMTS and other systems.

DMTS has continued to serve a critical role in the EEDM Department's technology and operational infrastructure. The system enables improved, standardized, and accurate tracking and regulatory reporting, tools to effectively manage third party implementation contractors and market partners, detailed tracking of customer projects, and both accurate and timely incentive processing. The DMTS provides enhanced controls for managing our portfolio of programs and for improving operational performance. The data stored within the DMTS will continue to lead to program administration efficiency as well as provide meaningful insight to customer behavior in an effort to drive new innovation and expand customer participation. DMTS investment will support the scaling up of EEDM programs and the management of new innovative programs. The technology and controls configured within DMTS will help provide cost-effective program management and accuracy of energy savings. Furthermore, the DMTS will continue to improve operational efficiency of EEDM programs and overall satisfaction of customers that participate in the programs. With additional investment, the DMTS can continue to maintain its role as the foundational platform for EEDM program operation and management.

For the period of 2020-2022, the EEDM Department is planning to implement enhanced Customer Relationship Management capabilities within the DMTS in order to expand customer participation and better service the opportunities for energy savings and demand reduction for our customers across all of our programs. From a savings standpoint, the DMTS foresees the need to develop an Evaluation, Measurement, and Verification ("EM&V") module across our portfolio of programs to allow for near real-time focused evaluation and review of measure and project level savings within our portfolio of programs to improve program design, management, and planning. In preparation for the future role of AMI within Company operations and EEDM Program offerings, the DMTS will need to design, implement, and review savings impacts related to EM&V 2.0 (meter based savings). Based on the increased volume of programs and incentive spend, it will be necessary for the DMTS to continue to develop/expand financial forecasting tools for utilization by the EEDM Department. Finally, it is anticipated that there will be the need to implement new future programs onto the DMTS platform as part of the continued evolution and advancement of the EEDM portfolio of programs.

In addition to the capital funding described above, the Company also requests O&M funding for the period of 2020-2022. DMTS Staff member labor had previously been in capital based on the overall quantity and level of implementation and new work. Effective 1/1/2019, all DMTS staff members are classified as O&M due to the change in focus to maintenance and updates to previous capital implementation work. O&M funding is required for the following:

- Daily maintenance, support, and testing for all existing EEDM programs configured on the DMTS platform,
- Program changes related to workflow and incentive,
- Scheduled Technical Resource Manual measure updates,
- Changes/updates associated with EM&V reports and activities,
- Enhancement requests,
- Maintenance and support activities for existing DMTS interfaces to ensure continued successful production level operation, and
- Future maintenance and support for current capital projects once implementation is complete.

c. **DRMS:** DRMS supports the management of enrollment, event initiation, performance monitoring, and settlement of the Company's DR programs. This system enables Con Edison to efficiently interact with customers enrolled in DR programs and manage peak demand. DR resources, an integral subset of DER portfolios, are used to lower network peaks on peak summer days as well as to alleviate operational contingencies.

Between 2016 and 2018, the Company determined its legacy DRMS was not a viable product for future needs, and through a competitive bid process, it scoped and developed a new DRMS. In 2018 OATI was selected as the new DRMS provider. Phase 1 of this new system will provide the base functionality to support the Rider T DR programs and will be implemented during 2019. To prepare for the system transition, Con Edison intends to operate the new system in parallel with the old DRMS to test and validate the system in a live environment during the 2019 DR season.

The DRMS is a key operating tool used to support a portfolio of DR programs, which have substantially grown in recent years. As these programs grow in number and complexity throughout 2020-2022, they will require enhancements to the new tool, such as the consolidation to a single system of record, and the flexibility to adapt to changes in tariff rules. The Company will implement phase 2 of the new DRMS implementation to cover enhanced reporting and settlements for Rider T during the rate period. Also during this period, the Rider L residential programs will be scoped for implementation in the new system.

These enhancements consolidate commercial and residential DR programs into a single system of record, which allows Con Edison to efficiently scale DR as more customers become eligible to participate through AMI and the purchases of smart air conditioners and thermostats. This will also improve forecasting and reporting to estimate the curtailment resources available as well as the performance of those resources when called upon to support a grid need.

d. **Demand Management Analytics Platform ("DMAP"):** DMAP refers to the collection of demand management use cases that leverage the Company's enterprise big data analytics platform. DMAP will provide a central repository of EEDM data sources and will apply advanced analytics to derive actionable insights to improve EEDM programs. It is essential to support higher level analytics in support of the design, delivery, and evaluation of the portfolio of programs and other related initiatives implemented.

In 2016 – 2017, we conducted an open bid RFP process to select a platform to support the AMI implementation project. C3 IoT ("C3") was selected as the vendor to provide the platform, which is referred to as the EDAP. Due to the proprietary nature of the platform, C3 was also used as the vendor to install and configure their platform for use by Con Edison. The Company will also engage C3 as the vendor to configure and enhance the existing EDAP to perform as the DMAP allowing the Company's energy efficiency efforts to take advantage of an enterprise-scale solution already established by IT. This enables more efficient integration with previously modeled and stored data and analytic tools, and also enables the sharing of EEDM data with the rest of the organization. It is important to note that work could not begin on DMAP until the completion of the EDAP project.

During the latter half of 2017, the majority of DMAP work involved negotiating the Statement of Work ("SOW") for the first iteration of DMAP. The SOW included the implementation of several use cases, including:

- Deploying the C3Energy Management application,
- Modeling energy efficiency customer participation propensity,
- Evaluating energy savings from a deployed energy efficiency measure,
- Predicting the savings available from an energy efficiency measure at the facility level,
- Developing end of year savings reports, and
- Visualizing EEDM forecast dashboard.

These use cases are deemed to be a starting point for a much larger set of use cases. It also included determining which data sets are already loaded into EDAP that can be leveraged for DMAP use and the additional datasets required for the implementation of the use cases. Implementation began in May 2018 and is expected to continue through the first quarter of 2019.

As the initial implementation nears completion, work will begin on expanding the number of use cases executing on the platform. This will require adding other data sources or expanding the current set of data sources. This may include contracting data scientists and other business intelligence professionals to reap as many benefits from the platform as possible. It is anticipated this expansion will continue in 2020-2022, requiring one (1) incremental FTE.

With the upcoming influx of AMI data, DMAP will be expanded even further to make use of this data. Con Edison will use DMAP to more effectively and efficiently scale its electric, gas, and targeted EEDM programs to expand reach, deepen savings, and manage costs. This will include optimization of sales and marketing activities via descriptive and predictive analytics to improve program targeting and efficiency measure cross- / up-selling; more efficient operations via improved self-service and / or automated analytics

& reporting and advanced savings forecasting and measurement; and identification of opportunities to optimize program design and activities across programs, customer segments, and commodities.

3) Information Sharing

The goals for Information Sharing include Information Management and Customer Engagement. Information Management focuses on the collection, analysis, and sharing of granular distribution system and customer data to customers and authorized third parties. Customer Engagement focuses on regular engagement with customers through market platforms and portals.

a. **Web Service Interface:** EEDM is tasked with meeting New York City legislation of providing building owners with their whole building aggregated consumption data, i.e., LL84, which requires annual benchmarking data to be submitted into the EPA's online tool called Portfolio Manager by owners of buildings with more than 25,000 square feet. EEDM implemented an interface to standardize and streamline the customer approach to comply with LL84 by having Con Edison upload their consumption data directly into Portfolio Manager.

   In 2017, EEDM, in conjunction with Con Edison's IT, implemented the Con Edison Portal for NYC Benchmarking. The Portal allows building owners or their authorized representative to request aggregated data for a specific building. The data is then automatically uploaded to Portfolio Manager.

   After the initial release of the portal in January 2018, several areas of improvement were identified. Monthly updates to the Portal throughout 2018 contained enhancements, user experience improvements, and fixes. Additional enhancements will continue through 2019, the major one being the implementation of a module to handle a "Campus", defined as two or more buildings which share a common heating system. This is treated in a specific manner in Portfolio Manager and the Portal must be able to properly upload the data for campuses.

   In 2020 – 2022, all the major modules are expected to be fully deployed and no capital funding is requested. However, continued support and maintenance of the portal and its users is required, which must now be treated as O&M as the Company shifts focus from development of the interface to maintenance and support. Support is being requested for 1.5 IT resources combining one (1) FTE and 0.5 consultants. Support will also be needed from the EEDM department which is a 0.5 resource to be filled by a consultant.

The DSP systems described above either leverage or improve upon existing assets or are allocated for new systems that support required DSP functionality. The initial investments are focused on building the necessary interfaces to engage customers, increase the volume and granularity of data, and enable greater DER penetration.

Justification Summary:

Con Edison has already begun, and will continue to develop, the implementation plan for building the DSP. The building blocks described above are the incremental elements required to support the functionalities of Con Edison acting as the DSP Provider. These investments also further State policy goals, including those of the REV proceeding: enhancing customer knowledge and tools that support effective management of their total energy bill, animating markets and leveraging customer contributions, enhancing system wide efficiency, promoting fuel and resource diversity, enhancing system reliability and resiliency, and reducing carbon emissions[4]. Finally, several of these investments (Modernizing protective relays, VVO, and DERMS) support Con Edison's Grid Innovation objectives.

Supplemental Information:

- Alternatives: The alternatives to this proposed incremental approach to building a DSP would involve changing the timing or deployment of the DSP components.

  Deploying more slowly than proposed risks losing momentum for viable initiatives and missing opportunities to advance key policy objectives. The DSP development is an evolution, which is designed for early strategic investments to build momentum and bring DSP functionalities online in time to meet policy objectives.

  Each proposed DSP component supports a key functionality of the envisioned DSP, as described above. The process of integrating DER with forecasting through planning and operations requires many platforms to work together. Removing or reducing the capability of platform components piecemeal would jeopardize the performance of the entire DSP.

- Risk of No Action: No action is not an acceptable course for several reasons. Primarily, it reinforces the status quo in the face of changing customer preferences, the continuing deployment of AMI, and increased adoption of DER by our customers. Also, as State policy objectives evolve, a lack of DSP functionality would hamper Con Edison's ability to support new policy goals, including those under REV, and present challenges to Con Edison's regulatory compliance. A lack of support for the various DSP systems and functionalities would also result in a missed opportunity to leverage and achieve greater value from the parallel Company investments in AMI and Digital Customer Experience ("DCX").

- Non-financial Benefits: By building the DSP, there is a path for greater penetration of DER and ultimately achieving the REV goals. The DSP, coupled with the Grid Innovation initiative are designed to evolve the electric distribution system over time to a future state that leverages state of the art technologies in an optimal way to meet policy goals, and evolving customer expectations.

- Summary of Financial Benefits (if applicable) and Costs:
  The costs of continuing the fundamental DSP capabilities, and expanding capabilities are outlined in the tables below:

[4] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding (issued April 25, 2014), p. 1.

Total DSP Capital Requests ($000):

Component	Investment	2020	2021	2022	Total
DER Integration	VVO	$14,300	$14,300	$14,300	**$42,900**
	Modernize Protective Relays	$12,600	$12,600	$12,600	**$37,800**
	IOAP	$1,300	$1,300	$1,300	**$3,900**
Market Services	DERMS	$2,800	$2,800	$2,800	**$8,400**
	DMTS	$1,600	$1,600	$1,600	**$4,800**
	DRMS	$1,300	$1,300	$1,300	**$3,900**
	DMAP	$1,300	$1,300	$1,300	**$3,900**
Information Sharing	Web Service Interface	$0	$0	$0	**$0**
	Total	**$35,200**	**$35,200**	**$35,200**	**$105,600**

Total DSP O&M Requests ($000):

Component	Investment	2020	2021	2022	Total
DER Integration	IOAP	$0	$0	$0	**$0**
	Modernize Protective Relays	$0	$0	$0	**$0**
	VVO	$0	$0	$0	**$0**
Market Services	DERMS	$0	$0	$0	**$0**
	DRMS	$0	$0	$0	**$0**
	DMTS	$1,705	$2,022	$2,338	**$6,065**
	DMAP	$160	$303	$327	**$790**
Information Sharing	Web Service Interface	$225	$225	$225	**$675**
	Total	**$2,090**	**$2,551**	**$2,890**	**$7,530**

- Technical Evaluation/Analysis: The DSIP includes many technical evaluations and analyses that will guide the decision making for the building block programs. These analyses cover:
  - DER capacity analysis supported by load flow analyses,
  - Analysis of the impact of greater DER penetration on the Network Reliability Indicator,
  - Analysis of locational benefits and costs,
  - Lessons learned through demonstration projects,
  - Analysis of how each type of DER reduces peak load and energy usage, and modifies load shape, and
  - Analysis of the costs and benefits of VVO.

- Project Relationships (if applicable):

  - AMI – AMI supports REV initiatives and the development of the DSP by facilitating enhanced voltage control and enhanced monitoring. This allows for more granular information which is necessary for location-based analysis and to enable providing clearer market signals.
  - DCX – DCX ensures the same look and feel across Con Edison websites. This connects to the DSP in the establishment of the customer-facing portals for accessing their own usage data and interconnecting DER.
  - GIS – As a foundational Grid Innovation investment, an enterprise GIS will provide the utility with the ability to accurately locate and model the various DER attributes in a single system of record that can be exported for load flow and optimization. It will be leveraged by DERMS along with many other utility systems. Further discussion of GIS is included in the Electric Infrastructure and Operations Panel ("EIOP") testimony and associated white paper included in the exhibit entitled EIOP-3.

- Basis for Estimate: As the building blocks for the DSP are discrete projects and largely leverage existing projects with incremental improvements, the costs were estimated based on scope of work estimates and/or current costs.

Annual Funding Levels ($000):
Capital
Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Actual 2018
Labor			$306	$793	$3,034
M&S			$0	$2,784	$3,327
A/P			$2,014	$7,067	$9,889
Other			$142	$1,225	$1,995
Overheads			$222	$1,679	$3,606
Total			**$2,683**	**$13,548**	**$21,851**

Future Elements of Expense

EOE	2019	2020	2021	2022	2023
Labor	$4,000	$5,400	$5,400	$5,400	-
M&S	-	-	-	-	-
A/P	$13,190	$22,100	$22,100	$22,100	-
Other	$1,000	$1,300	$1,300	$1,300	-
Overheads	$3,000	$6,400	$6,400	$6,400	-
Total	**$21,290**	**$35,200**	**$35,200**	**$35,200**	-

O&M
Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P						
Other						
Overheads						
Total					**N/A**	

Future Elements of Expense

EOE	2019	2020	2021	2022	2023
Labor		$520	$646	$665	
M&S		$1,570	$1,905	$2,225	
A/P		$0	$0	$0	
Other		$0	$0	$0	
Overheads		$0	$0	$0	
Total		**$2,090**	**$2,551**	**$2,890**	

CUSTOMER SERVICE SYSTEM

BUSINESS PLAN

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

JANUARY 2019

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EXECUTIVE SUMMARY

The Consolidated Edison Company of New York, Inc. ("CECONY" or "Company") has completed a comprehensive evaluation of its legacy Customer Service System ("CSS") capabilities against a forecast of growing business, customer and regulatory demands. A CSS is one of the most strategic and mission-critical systems within the utility enterprise, providing the technological capability for delivering high quality service to customers and enabling the demands of a number of new investments and public policy requirements. The Company's long-range plans emphasize the importance of increasing the focus on customer demands in the midst of dynamic changes in technology and the marketplace. Customers are increasing their interactions with the Company through new channels of communication and demanding detailed information about their energy usage, service options, rate options and billing choices. Overlaying this shift in customer expectations are New York's evolving energy policy initiatives, tariff and program offerings that continue to add complexity to a wide range of customer service transactions handled by the Company. CECONY has responded to these dynamic changes by investing in new technologies that are empowering customers with energy choices and meeting their desire for a next-generation customer experience.

One of the driving forces behind the transformation of the utility sector is technology, which is fueling the increased digitalization and ultimately, empowering customers. Among the many technology platforms that are enabling this transformation, the CSS is foundational to the effort, as it is the central repository of customer, billing, and account history data that must be used and leveraged by many Company internal information technology ("IT") systems. A utility's CSS performs essential customer-service-related functions, including customer account management, billing, credit and collections, and accounts receivable services for electric and gas customers.

CECONY is not alone in its reliance on a legacy CSS platform that was designed to meet specific utility needs and requirements that were identified 45 or more years ago. Many utilities across the country face similar challenges with legacy CSS platforms that are moving towards obsolescence in the face of headwinds from increasingly complex rates, exponential growth in data processing requirements, and an unprecedented level of customer engagement that will continue to increase. In light of these realities, CECONY evaluated the business case to replace its legacy CSS with a new, state-of-the-art platform. As described in the New York Public Service Commission's ("NYPSC") *Order Approving Electric and Gas Rate Plans* in CECONY's 2016 electric and gas rate cases, during the period from mid-2018 through mid-2023, CECONY will replace its existing CSS with a suite of systems to better support customer service and billing.[1]

By leveraging new technologies to meet the growing business and regulatory demands that are defining the New York energy landscape, CECONY's investment in a new CSS will result in both quantitative and qualitative benefits. The Company intends to maintain the legacy CSS architecture while executing the planning elements and implementation for the new CSS. The planning, procurement and implementation strategy for the new CSS is coordinated with Orange and Rockland Utilities, Inc. ("O&R").[2] The new CSS project includes the replacement O&R's legacy Customer Information Management System ("CIMS").[3] The joint procurement and system replacement effort is consistent with the enterprise-wide procurement strategy adopted by CECONY and O&R in response to the audit recommendations from NorthStar Consulting Group ("NorthStar"),[4] which was retained by the NYPSC to conduct an independent management and operations audit of CECONY and O&R in 2016.

[1] Cases 16-E-0060 and 16-G-0061, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric and Gas Service*; Order Approving Electric and Gas Rate Plans (issued January 25, 2017) , see Attachment A, Joint Proposal, dated September 19, 2016, (p. 85).
[2] CECONY and O&R are referred to collectively as the "Companies."
[3] O&R's CIMS business plan was filed with the NYPSC on June 15, 2018 as an exhibit to the Customer Service Panel's Update/Rebuttal testimony in Cases 18-E-0067 and 18-G-0068.
[4] Case 14-M-0001, *In the Matter of the Comprehensive Management and Operations Audits of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.*, Final Report submitted by NorthStar Consulting Group, dated April 21, 2016 ("Final Audit Report").

Cost Benefit Summary

The Companies developed a formal business case to evaluate the financial and functional justifications for updating their CSS capabilities through a replacement with a new, state-of-the-art system. CECONY estimates $421 million in capital that includes Allowance for Funds Used During Construction ("AFUDC") through 2023 to plan, analyze, design, build, test, and deploy this new system. CECONY also estimates $46 million of operation and maintenance expenses ("O&M") to implement and stabilize the new CSS through 2023 (Table 1). These costs reflect a cost allocation of approximately 92.75 percent / 7.25 percent between CECONY and O&R.[5]

Table 1: Estimated Capital and O&M Costs for CSS Replacement through 2023

Estimated Cost allocation ($m)	O&R	CECONY	Total Cost
Capital	**$34**	**$421**	**$455**
O&M	**$4**	**$46**	**$50**
Total ($m)	**$38**	**$467**	**$505**

As part of the analysis the Companies conducted to support the decision to invest in a new CSS, potential savings have been identified that CECONY will achieve once the new CSS is operational. These savings are detailed in the Cost Benefit Analysis section of this Business Plan, as part of a discussion of financial and non-financial benefits. In summary, the major benefits of the new CSS includes:

- Reducing annual costs by approximately $23.4 million for expenditures such as CSS Sustainability, IT support and contractor spend related to the legacy CSS ($12.7 million in Capital and $10.7 million in O&M);
- Avoiding $38.4 million in annual costs, such as those associated with future capital spend on the legacy CSS related to customization as well as mainframe retirement and other cost elements (approximately $31.5 million in Capital and $6.9 million in O&M);

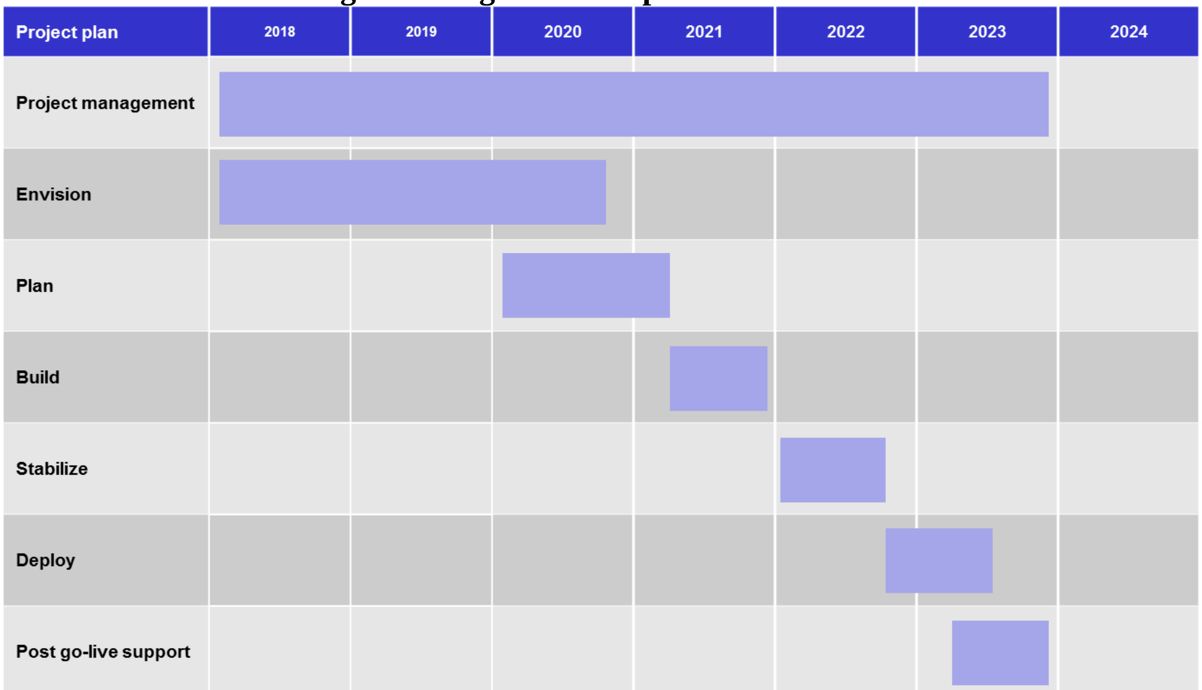
[5] See Consolidated Edison Corporate Accounting Procedure, Accounting for Transactions between CECONY and ORU, GAP-040, August 9, 1999

- An estimated NPV over the course of the new CSS deployment through to 2040 is expected to be approximately $1.3 billion for CECONY and O&R;
- Leveraging the ability to configure the new CSS versus developing customized programming to handle many business requirements that currently must be addressed with code changes (*e.g.*, implementation of Reforming the Energy Vision ("REV") initiatives, rates, new programs, credit and collection processes, customer notifications and correspondences, and billings);
- Supporting data privacy and cybersecurity controls;
- Achieving a customer centric model to enable customer relationship management and raise the profile of call center representatives to advise customers on energy programs, while continuing to support CECONY's Digital Customer Experience ("DCX") goals;
- Providing a robust, flexible foundation for customer account data and transactions that can interface with evolving technologies and facilitate enhanced customer relationship management across a growing array of platforms;
- Implementing a platform that will be able to handle more diverse billing determinants;
- Benefiting from a comprehensive, utility-focused, commercial off-the-shelf ("COTS") solution through regular base product upgrades by the vendor which will include the collective needs of utilities that use their CSS products;
- Allowing access to a broader pool of technical and business resources by utilizing a COTS CSS;
- Creating a flexible data architecture that allows real-time access to customer information rather than depending on current batch processes; and
- Standardizing business rules and technology platforms across both CECONY and O&R.

Implementation Plan and Proposed Schedule

The proposed implementation is expected to be complete by summer of 2023, by which time CECONY's legacy CSS platform will be over 50 years old. The figure below provides the proposed high-level implementation schedule.

Figure 1: High Level Implementation Plan



In conclusion, the utility environment is evolving so as to afford customers with more options to participate in a diverse array of clean and traditional energy solutions. A key component to a utility's success in this environment is a modern CSS which will facilitate the delivery of efficient solutions to address increasing customer needs and expectations.

CUSTOMER SERVICE SYSTEM BACKGROUND

CECONY, with its legacy CSS technologies, is challenged to maintain support for innovative rate structures, complex billing requirements, new regulatory mandates and interval meter data derived from deployments of advanced metering infrastructure ("AMI").[6] This section discusses the history of the CECONY CSS replacement planning effort and the various customer, technology, and regulatory drivers that initiated this effort. In addition, this section discusses some of the challenges of CECONY's legacy CSS.

CECONY's CSS Replacement Assessment

CECONY's preliminary CSS evaluation extends from a comprehensive Risk Assessment and Risk Mitigation analysis that the Company initiated in 2011 to evaluate risks associated with the ongoing operation of its legacy CSS. The primary objective of this early initiative was to maintain the effectiveness and reliability of the legacy system as CECONY began the process of developing a future state assessment of CSS replacement options. By 2013, CECONY had begun a comprehensive CSS planning effort and retained a consultant to evaluate its current systems against future business and regulatory requirements. As part of this planning effort, CECONY formed a cross-functional team with members from business operations, technical operations, subject matter experts, and consultants who possessed industry expertise with utility CSS applications. The planning effort focused on gathering information about the operational use and capabilities of the legacy CSS platform, which allowed the Company to map out future needs against available replacement alternatives.

[6] See, for example, the following rate case proceedings and CIS industry analyses:
Southern California Edison, General Rate Case A. 16-09-001, September 1, 2018.
Avista Corporation, Docket UE-140188 and UG-140189, February 14, 2014
Cases 17-E-0459 and 17-G-0460, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas and Electric Corporation for Electric and Gas Service, July 28, 2017
"CIS Trends and Implementations 2011", Chartwell, Inc. September 2011. https://www.chartwellinc.com/more-utilities-look-to-replace-cis-as-system-demands-increase-market-evolves-into-competitive-landscape-for-vendors-chartwell-reports/
"A CIS Survey and Industry Perspective" presented by TMG Consulting at CS Week on April 29, 2015, for additional information on CIS replacements in the industry.

The analysis identified a number of potential CSS alternatives, one of which evaluated continuation of the legacy CSS system. From that list of alternatives, the Company identified a select number of viable options for further detailed analysis. CECONY conducted a series of workshops to identify the best solution considering cost, scheduling and logistical risks associated with implementation of each viable option. The Company concluded that full replacement with a COTS CSS was the most appropriate solution, as it enables process standardization and provides advantages associated with the Companies' use of a common platform. This culminated in the CECONY 2014 Customer Information System Application Plan Report.[7]

In 2016, NorthStar released the Final Audit Report relating to its management and operations audit for both CECONY and O&R. The Final Audit Report focused on several broad subjects, including cross-functional areas that have a significant impact on the operations of both Companies. A key recommendation of the Final Audit Report was that CECONY and O&R should increase the level of sharing of best practices across both Companies by developing a standard protocol that would explore opportunities for potential cost savings resulting from standardized processes or economies of scale. In response to the audit recommendation, the Companies developed a standardized best practices protocol, including procedures for when to use the protocol and how to analyze processes for completing similar work at O&R and CECONY.[8] The protocol is used to determine whether best practices exist; and if so, how to standardize them. The effort seeks to bring standardization to a number of functional areas and programs across CECONY and O&R, including AMI, Supply Chain, Customer Service and IT.

The positive features of standardization and achieving economies of scale also extends to technology adoption and transformation. In the technology space, there have been a number of initiatives that were pursued across both Companies, such as DCX, AMI, Green Button Connect, Enterprise Data Analytics Platform ("EDAP") as well as other Distribution System

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[7] In accordance with the NYPSC's February 21, 2014 Order Approving Electric, Gas and Steam Rate Plans In Accord with Joint Proposal ("Order") in Case No. 13-E-0030 et. al.

[8] O&R and CECONY responded to NorthStar's recommendation #1, pg. III-28 and is pending Staff review and closeout as of February 13, 2018.

Platform ("DSP") enabling technologies. CECONY and O&R have also pursued shared technology platforms for a Meter Asset Management System, Meter Data Management System, and the AMI Head End System, including shared support services for those technology platforms.

In CECONY's last electric and gas base rate cases finalized in January 2017, the NYPSC adopted electric and gas rate plans providing that CECONY will begin planning to replace its existing CSS commencing in mid-2018.[9] Given CECONY's plans to replace its legacy CSS, and the age of O&R's CIMS, both Companies are aligned with NorthStar's audit recommendation by exploring the potential synergies, cost savings, and operational and customer benefits of jointly developing a new CSS.

CECONY's CSS Pre-Implementation Effort

CECONY and O&R jointly engaged consultants to assist in evaluating the operational capability and functionality of each Company's legacy CSS/CIMS and develop a business case analysis that is contained in later sections of this Business Plan. For CECONY, the legacy CSS is a mainframe customer information system that was installed in April 1972. Since that time, computing technology, regulatory requirements, rate complexity and customer expectations have changed and matured, underscoring the critical nature of decisions on when and how to replace a CSS. In addition, New York's REV and other smart grid initiatives have introduced significant changes to how CECONY and O&R interact with customers, the types of rates and programs that must be supported, and the need for robust integration among the CSS and other operational systems, such as AMI. The CSS of today and the future must be flexible and adaptive to evolving business needs.

While the legacy CSS has served CECONY and its customers well for many years, CECONY has been modifying and customizing its legacy CSS for decades due to evolving regulatory and business requirements. This patchwork approach is resource-intensive and unsustainable with the advent of REV and technological leaps in the computing space. The legacy CSS cannot readily comply with new requirements and technology interfaces.

[9] Cases 16-E-0060 and 16-G-0061, Order Approving Electric and Gas Rate Plans, January 25, 2017

Moreover, the Company is finding that the legacy CSS is becoming increasingly difficult and expensive to enhance in the face of a set of growing complex rate structures and regulatory requirements, such as Community Distributed Generation ("CDG") and the Value of Distributed Energy Resources ("DER").[10]

The growing trend away from mainframe systems, such as CECONY's legacy CSS, is not surprising given the number of utilities planning for or implementing newer, state-of-the-art COTS systems. A new COTS system will provide improved capabilities for the Companies to meet expanding business needs and regulatory mandates. Without upgrading to a new CSS, the inevitable outcome is that CECONY's ability to leverage best practices of other utilities with legacy mainframe systems that grapple with the same logistical challenges will continue to decrease while at the same time, the complexity of integrations and functionality enhancements continues to accelerate.

Existing Functionality of CSS Platform and Challenges

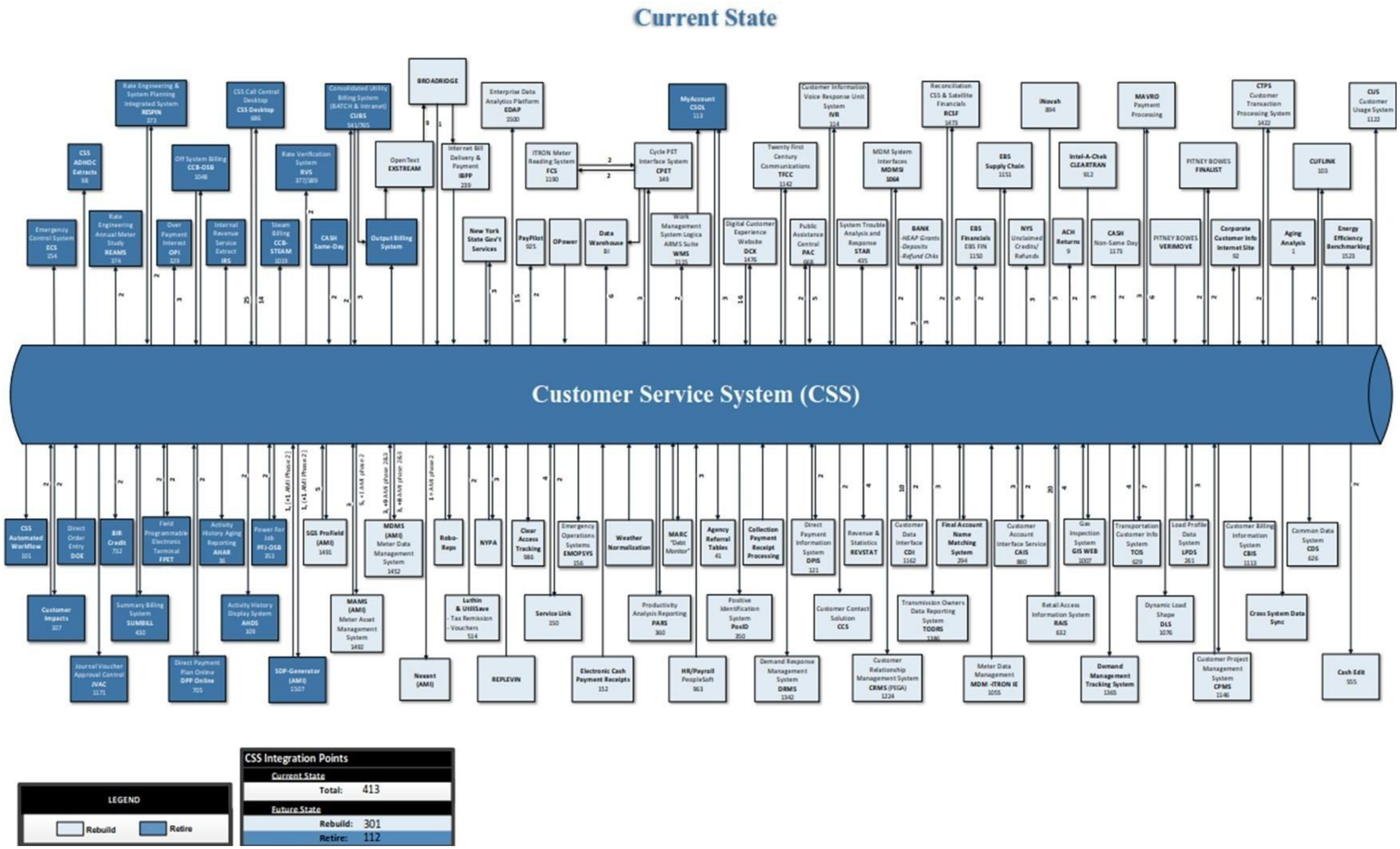
The current Customer Service IT portfolio comprises over 100 applications at the core of which is CECONY's legacy CSS, a mainframe-based application implemented in nearly 50 years ago, which has been continuously modified over the last few decades. The legacy CSS and its ancillary systems comprise just over 20 percent of the entire CECONY IT application portfolio and supports over 1,800 users from functional areas, such as Customer Operations, Customer Energy Solutions, Electric and Gas Operations, Rate Engineering, Legal Services and Corporate Accounting. CECONY's legacy CSS and sub-systems are highly complex and interdependent to deliver critical customer service functions, such as billing, energy-usage management, outage communications and demand-side management. As technology has advanced with the introduction of new business functions and regulatory mandates, such as smart meter data collection, Community Net Metering, Value of DER, the sub-systems and interfaces to CSS have become more complex and concurrently dependent upon both older and new technologies.

[10] Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

The legacy CSS was developed on what is considered outdated technology architecture and application system code. Over time, continued modification and sustainability efforts brought about by customer requirements and new regulations have increased complexity as well as higher investment costs in order to maintain the functionality of the legacy CSS. The legacy CSS and its sub-systems have evolved to become a complicated web of interrelated systems. The diagram below illustrates the current state complexity of the legacy CSS (Figure 2).

EXHIBIT___(CES-5)

Figure 2: CSS Integration Diagram



The number and complexity of system integrations to CSS have expanded considerably over the life of this legacy system first implemented in 1972.[11] For example, there are currently over 400 legacy CSS interfaces with multiple systems, and over 300 will need to be rebuilt or subsumed as part of the new CSS project. This trend of new system interfaces, rebuilds as well as maintaining system integrations, is expected to accelerate further in light of increasing volumes of regulatory requirements, new customer offerings that rely on complex rate design and program administration, development of DSP functionality, and an ongoing effort to engage customers with personalized experiences and clean energy solutions. CECONY is investing in multiple advanced technologies to modernize the grid to enable DER integration and distribution system market development, leverage customer data to drive adoption of clean energy solutions, and provide a next generation customer experience. These investments include, but are not limited to:

- Predictive data analytics;
- Advanced communications infrastructure;
- AMI;
- Energy efficiency and demand reduction program development through analytics;
- Distributed energy resources management; and
- Mobile billing features.

A number of these modern technologies listed above would require some level of integration into the legacy CSS platform, and because of the limitations of the legacy system, establishing the necessary interfaces is becoming more challenging, riskier and costly.

Level of Continued Investment in Legacy CSS

CECONY has engaged in numerous efforts related to improve and sustain the legacy CSS. The purpose of these efforts was to upgrade the original CSS programming languages to a more universally used and supported language, and implement functional enhancements and risk mitigation strategies. The overall objective of these investments was to maintain

[11] For example, New York State Energy Research and Development Authority ("NYSERDA") On-Bill Recovery ("OBR"), REV Rate Pilots, AMI, industry deregulation and Value of DER.

reliable hardware, operating systems, and software platforms so that the Company could provide quality customer service and encourage the development of new tools for customer engagement and bill management. However, continued investment in these upgrades comes at a cost to the business.

Other CSS enhancements have been made over the years in response to regulatory mandates, such as Recharge New York, Mandatory Hourly Pricing, Reactive Power, low-income program changes as well as NYSERDA On-Bill Recovery ("OBR"), to name a few. The NYSERDA OBR required changes to the legacy CSS alone totaled $1.3 million. With the projected future demands coming from business and regulatory requirements, legacy CSS enhancements will continue to drive investment absent a transition to a more modern system.

The complexity of the architecture and growing demands on the legacy CSS has continued to increase costs at CECONY with labor intensive efforts to integrate ancillary systems, and increased costs to achieve acceptable levels of functionality. An example of this is the CSS Desktop, which is a Windows-based application that resides over the mainframe-based legacy CSS session ("green screen"). The CSS Desktop application, which interfaces with the CSS mainframe and the database system which allows mainframe data to be used for reporting and system interfaces to other Company applications. The CSS Desktop application is used by CECONY Customer Service Representatives ("CSRs") to automate manual functions of the legacy CSS and deliver quicker transactions for inquiries than could be done by just using the CSS green screen application. This requires that CSS Desktop and the CSS mainframe application to remain closely synchronized and updated in concert with one another, increasing the complexity of maintenance and the coordination of changes to both systems.

Reliance on Antiquated Programming Languages

The legacy CSS uses an antiquated Common Business-Oriented Language ("COBOL") as its core programming language. COBOL dates back to 1959, and its use today is limited to legacy mainframe systems in finance, banking, utilities and other sectors. As legacy systems are systematically being replaced with modern day platforms, and experienced COBOL programmers are reaching retirement age, CECONY is increasingly challenged to attract personnel that can fulfill the necessary programming requirements associated with the legacy CSS platform. The current market for computer programmers not only lacks COBOL programmers, but today's computer engineers and technicians have little interest in joining companies relying on mainframe systems. Furthermore, programmers and technicians trained in other legacy technologies, such as ASSEMBLER and Random Access Management Information System ("RAMIS") programming languages, in which CSS programs were originally developed, are also diminishing. Without the implementation of a modern CSS platform, the legacy CSS will be increasingly difficult to support and maintain, resulting in the inability to expand and modify CECONY's CSS effectively. In addition, should IBM release future updates to its mainframe operating system or hardware platforms, these older programming languages may not be supported.

NON-FINANCIAL CUSTOMER BENEFITS

The new CSS will support reliable customer service and continual improvement of the customer experience by providing a state-of-the-art platform that can adapt to future policy initiatives, technological innovation, and future rate designs. The following section details these and other non-financial customer benefits that support the new CSS business case.

New York Energy Policy Initiatives

The energy industry landscape in New York has changed over the last decade. Looking forward, new and evolving energy policy initiatives, tariff and program offerings (*e.g.*, REV, Value of DER, Community Net Metering) will continue to add complexity to a wide range of customer service transactions handled by CECONY systems and CSRs. As public policy encourages more rate options and increased customer participation in energy solutions, CSS system changes that are necessary to support implementation of the State's energy policies will likely increase at a rapid pace. Benefits to customers related to a new CSS include the development of enabling tools and services to better understand their energy usage, costs and needs in a cost effective and time efficient manner, such as:

- **Pricing Mechanisms:** The DSP's purpose is to facilitate modernization of the electric grid in the context of competitive electricity markets, where transactional energy platforms can promote new pricing mechanisms. A new CSS will enable CECONY to handle more diverse billing determinants.

- **Speed to Market**: Due to the age and architecture of the legacy CSS, the Company incurs additional costs in the form of capital and O&M, for internal labor, to achieve functionality to support regulatory initiatives. Today's COTS CSS solutions can accomplish functional enhancements through business-side configuration changes, as compared to IT-side programming changes.

- **AMI and Alternative Rates and Programs:** Alternative rate designs and innovative customer offerings are expected to accelerate with implementation of the State's energy policy initiatives. Since the timing of the AMI meter deployment completion and the implementation date for a new CSS platform are expected to be in close proximity, new CSS capabilities will become a necessary and enabling technology platform to position CECONY to respond effectively to future policy initiatives.

Technology Innovation in Customer Service

There have been significant changes within the recent past in the model for effective customer service. Customers have always expected friendly, efficient and reliable service, but with the development of new technologies, customers increasingly expect a customer-centric, individualized experience similar to that offered in other industries (e.g., retail, media, and telecommunications). In the current environment, a positive customer experience includes a seamless "one-stop shop" transaction, with the ability to interact online and through mobile devices and social media, and to access self-service solutions for traditional service transactions.

- **Customer Data and Engagement:** The new CSS will play an important enabling role in the process of analyzing customer energy profiles. The objective is to provide targeted and attractive DER and EE offerings to the customer. Better access to customer data will enhance the customer segmentation analysis so that appropriate programs can be matched with the right customers.

- **Leveraging a modern CSS:** The new CSS provides a flexible data architecture that allows real-time access to customer information rather than depending on current batch processes.
- **Data model:** The transition from a CSS with a premise-based architecture to customer-based one will benefit customers by allowing multiple service contracts to be associated with an individual or corporation. A customer-based data model is required to enable a future where individuals and entities have a number of methods for managing their energy and communication options to interact with CECONY and allows for a customer-centric view. Currently, the CECONY premise-based model is challenged as it cannot provide a comprehensive view of the data or usage to the customer, the CSR or a marketer if that customer is associated with more than one building.

Other Benefits

Other peripheral, non-financial benefits are described below.

Information Access

CECONY has an obligation to respond to requests for information that the NYPSC deems essential for the formulation of regulatory policy. The scope of reporting and data submissions continues to place growing demands on the Company. CECONY strives to meet the NYPSC's information and reporting requirements in both an efficient and accurate manner. For some information requirements, the CSS repository of customer information becomes the foundation for reporting. For instance, as part of the Commission's *Proceeding on Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-residential Retail Energy Markets in New York State* in Case 12-M-0476, the Department of Public Service Staff ("Staff") issued numerous interrogatories to CECONY and O&R seeking customer specific data. This data would allow for the calculation of the price difference between the Energy Services Company's ("ESCO") price and what the customer would have paid assuming that service had instead been provided by CECONY pursuant to its NYPSC-approved rates.[12] In order for CECONY to compile the price data, the Company had to employ multiple systems, including the legacy CSS, as well as the Consolidated Utility Billing System ("CUBS"). This was a manual, labor-intensive process that took a significant amount of time to test, compile and verify millions of customer data records. A new CSS platform is expected to provide meaningful improvements for the efficient and effective access of customer data to provide the NYPSC with a complete view of the marketer and price history for each customer.

In addition, CECONY provides information to the NYPSC relating to its customer service metrics. The accuracy of that information was the focus of an audit performed by

[12] Cases 12-M-0476, *Proceeding on Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-residential Retail Energy Markets in New York State*, Order Adopting a Prohibition on Service to Low-Income Customers by Energy Service Companies (issued December 16, 2016).

Overland Consulting ("Overland") on behalf of the NYPSC.[13] CECONY faced challenges in producing account-level details for recent adjusted bill totals from a month selected by Overland. In addition, the Company experienced difficulty in explaining adjusted bill reason codes designations. In both cases, the issue stemmed from an inability to analyze the programming logic in queries that pull data from the legacy CSS system. A new CSS platform would provide meaningful improvements for accessing customer data to provide the NYPSC with the necessary information.

Productized Solution and Resource Availability

As the utility industry migrates from mainframe-based systems like the CECONY legacy CSS and installs state-of-the-art platforms, vendors and their offerings are expected to increase and competition should grow. CECONY will have more options regarding software add-ons from companies providing COTS CSS consulting services due to a much wider installed base of competing applications. Through regular base product upgrades, the new CSS will leverage the collective needs of the utilities that use COTS. As the industry evolves, so too will the new CSS. Furthermore, moving from a mainframe solution, reliant on COBOL and other archaic programming languages, to a COTS architecture provides access to a programming labor pool that is broader and deeper.

CSS Platform Standardization

With a single, common CSS platform, CECONY and O&R customers would benefit from the implementation of state-wide regulatory initiatives (*e.g.*, surcharges in support of emissions-free and renewable energy sources) as the work associated with the regulatory mandate would occur once for both Companies. In addition, the Companies can develop common practices associated with system upgrades or maintenance to the CSS, as any modifications/enhancements would only require updating on one billing system rather than

[13] Cases 13-M-0314, *Issue a Request for Proposal for an Independent Third-Party Consultant to Conduct a Review of the Accuracy and Effectiveness of Certain Reliability and Customer Service Systems at all Gas and Combination Gas and Electric Utilities in New York State that Provide Statistics to the Commission on the Services They Provide Customers*, and 15-M-0566, *In the Matter of Revisions to Customer Service Performance Indicators Applicable to Gas and Electric Corporations*, Order Releasing Report and Providing Guidance on Response, (issued April 20, 2016).

the current process that requires updates/modifications on two separate systems. Furthermore, the implementation of common CSS will allow CECONY and O&R to streamline access controls and authentication improvements. The CECONY and O&R vision is to implement common controls to protect customer data that provides a holistic enterprise-wide view that is risk-based, and technology and business focused.

Data Protection and Privacy

A new CSS with a modern platform will allow the Companies to better protect against emerging cyber and privacy threats and mitigate issues quickly. Further details on data protection and personally identifiable information are in the Implementation Plan section of this document.

COST BENEFIT ANALYSIS

The Companies engaged a third party vendor (“Vendor”) to perform an assessment for a new CSS through a competitive process in August 2017. The Vendor built upon the assumptions and pre-work derived from the CECONY 2014 Customer Information System Application Plan Report. The CSS project team partnered with the Vendor to develop a cost/benefit analysis where each cost and benefit assumption was validated through an iterative review process. Between October 2017 and May 2018, the CSS project team and Vendor worked together to conduct a thorough planning effort to replace the legacy CSS systems and update assumptions that were used to estimate the project’s anticipated costs and benefits. This section provides details of all cost reductions, avoidance and benefits outlined in the business case.

CSS Platform Replacement Cost Scenario Analysis

In developing a comprehensive overview of the cost to implement a new CSS, the Company worked with the Vendor to develop the cost estimates for an enterprise-wide CSS platform. The Vendor has substantial experience implementing CSS platforms of comparable size and complexity.

Key factors that are embedded into the CSS cost estimate include: (1) an assessment of the current state business processes, (2) integration and technical architectures, (3) labor resources, (4) non-labor costs, such as hardware and software, and (5) indirect costs.

The capital and O&M determination for the labor costs were driven by an analysis of the activities that would be performed by resource type and role, for each phase of the project, to determine whether the effort for that phase should be capitalized or expensed. Similarly, for the non-labor costs, the capital and O&M determination followed Plant Accounting rules and Generally Accepted Accounting Principles (“GAAP”).[14]

[14] Consolidated Edison Corporate Accounting Procedure, Accounting for Transactions between CECONY and ORU, GAP-040, August 9, 1999.

CECONY CSS Cost Replacement

As shown below, the estimated cost of a joint CECONY and O&R new CSS, for both O&M and capital through 2023, is $505 million. The first step in determining the cost impact was to estimate the overall cost for both CECONY and O&R through planning, designing, building, testing and deploying activities through 2023 and include the timelines noted in the electric and gas rate orders approved by the NYPSC in Cases 16-E-0060 and 16-G-0061.

Given that CECONY's legacy CSS is nearly 50 years old, and O&R's CIMS platform was 20 years old in May 2018, the Companies evaluated the level of cost reduction benefits that would accrue to CECONY as a result of a CSS replacement across both Companies. This analysis assumes that certain implementation activities would be performed concurrently such as project management, design of functional and technical specifications, development and testing of the new CSS. With a single common CSS platform, system implementation, testing, training and validation would occur in unison across the entire enterprise.

The next step was to apply accepted allocation methodologies for assigning cost responsibility to each of the Companies, which currently allocates approximately 93 percent of project costs to CECONY.[15] CECONY's share of total costs is estimated to be $467 million in capital and O&M through 2023.

Table 2: Estimated Capital and O&M Costs For CSS Replacement Through 2023

Cost allocation ($m)	O&R	CECONY	Total Cost
Capital	**$34**	**$421**	**$455**
O&M	**$4**	**$46**	**$50**
Total ($m)	**$38**	**$467**	**$505**

[15] Consolidated Edison Corporate Accounting Procedure, Accounting for Transactions between CECONY and ORU, GAP-040, August 9, 1999.

The following tables provide further details on estimated capital and O&M expenditures by cost category. [16]

Table 3: Estimated Capital Expenditures from 2019 to 2023 ($000)

EOE	2019	2020	2021	2022	2023
Labor	$3,672	$14,783	$20,763	$21,564	$7,206
M&S	-	-	-	-	-
A/P	5,508	39,657	46,543	56,129	22,867
Other	4,936	11,187	15,176	16,811	5,685
Overheads	-	6,652	9,343	9,704	3,243
AFUDC	958	3,638	8,563	14,892	4,761
Total	$16,288	$129,619[17]	$100,388	$119,100	$43,762

The CSS project has incurred approximately $12 million in capital costs in 2018. The new CSS will introduce new IT infrastructure to the Company. As such, associated implementation and ongoing O&M funds are needed to maintain the new systems brought online for the life of new CSS. The $23 million in O&M costs associated with the effort during the Rate Period include:

- Change Management & Training: These funds are needed for design, development and deployment of training materials and necessary toolkits for CSR and other impacted employees
- Operational Support: This includes additional CSR personnel support required to maintain operational performance as the new CSS goes into service. The Company expects to bring resources in around mid-2022 to begin onboarding and training
- Facilities: Facilities rental, maintenance and tax charges for project working space and associated communal areas for all project employees

Table 4: Estimated O&M Expenditures from 2019 to 2023 ($000)

EOE	2019	2020	2021	2022	2023
Labor	-	$1,221	$901	$3,749	$11,945
M&S	-	-	-	-	-
A/P	-	2,843	2,107	1,635	1,792
Other	935	2,708	2,559	2,465	3,478
Training Facilities	-	549	406	1,687	5,375
AFUDC	-	-	-	-	-
Total	$935	$7,321	$5,973	$9,536	$22,591

[16] Values in the tables may not sum exactly due to rounding.
[17] The $129.6 million of cost in 2020 includes $53.7 million of Oracle software costs that will not be charged to the CSS capital project. Pursuant to accounting requirements, the software costs were recorded in plant in service when the Company entered into the strategic agreement with Oracle in 2018.

O&M expenditures beyond the Rate Period are associated with post-go live system stabilization.

The following tables provide information on past capital and O&M expenditures associated with the new CSS project.

Table 5: Prior Actual and Forecasted Capital Costs for New CSS ($000)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018
Labor				$2,635	$4,545
M&S				-	-
A/P				-	$6,818
Other				-	-
Overheads				-	-
AFUDC				-	$663
Total				$2,635	$12,026

Forecasted 2018 capital costs are largely associated with new CSS pre-implementation work activities.

Table 6: Prior Actual and Forecasted O&M Costs for New CSS ($000)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor				-	-	-
M&S				-	$5	$7
A/P				-	-	-
Other				-	$33	$453
Total				-	$38	$460

The 2018 forecasted O&M expenditures for the new CSS project are largely associated with facilities and related maintenance costs.

Benefits Analysis

In developing the business case to replace the CECONY legacy CSS, the project benefits were identified based on how the new CSS will support the continued growth of the organization and continual improvement of the customer experience.

To accurately reflect the impacts of these benefits on the organization, they have been categorized into the following categories:

1) Non-financial: capabilities that will be critical to enabling the further growth of the organization but are not possible to link to a direct revenue or cost impact; and

2) Financial: capabilities that can be directly attributed to an impact on revenue and cost, which will be built into the five-year budget planning.

Benefits Analysis – Non- Financial

While developing the business case to replace CECONY's legacy CSS, non-financial customer benefits have been identified based on how the new CSS will support continual improvement of the customer experience through enablement or enhancement of state regulatory policy initiatives and other Company technology deployments. Detailed information on these benefits is addressed in the Customer Benefits section of this Business Plan, and is summarized below:

New York Energy Policy Initiatives

A new CSS will:

- Enable CECONY to handle more diverse billing determinants.
- Increase agility and efficiency of system modifications from to regulatory mandates through business-side configuration changes, as opposed to IT-side programming changes.
- Enable the Company to roll out program offerings and other initiatives to customers, such as alternative rate structures to reward energy conservation and other DERs, enabling customers to leverage data provided by AMI.

Technological Innovation in Customer Service

- Ability to efficiently and seamlessly extract and enhance customer data used for identifying and engaging customers with the appropriately tailored products and services.

- Leverage a modern CSS to support real time access to customer information as opposed to batch processes.
- Support customer centric strategies.

Other Benefits

- Ability to provide the NYPSC customer information efficiently.
- A comprehensive, utility-focused, COTS through regular base product upgrades by the vendor which will include the collective needs of utilities that use their CSS products.
- Allow access to a broader pool of technical and business resources by using a COTS CSS.
- Support data privacy and cybersecurity controls.
- Statewide initiatives (*e.g.*, surcharges in support of emissions-free and renewable energy sources) would only require updating on one billing system at CECONY and O&R rather than the current process that requires updates on two separate systems.

Across these non-financial benefit categories, a new CSS system will establish a more secure and sustainable foundation for the benefit of customers. It will provide a variety of core capabilities, as well as a more flexible CSS, that will be critical in deploying a wide range of functionality for current and future needs to support our customers.

Benefits Analysis – Financial

CECONY expects to achieve cost reductions by replacing the legacy CSS. This will include reductions in labor and vendor costs as well as the avoided capital costs associated with maintaining and enhancing the existing CSS. These avoided costs include routine and ongoing maintenance costs and technology investments to support legacy applications.

Financial Cost Savings

The new CSS will generate operational efficiencies resulting in additional reduced labor and maintenance costs, as shown in Table 7, valued at approximately $23.4 million annually.

Table 7: Estimated Annual Cost Reduction

Function	Description	Estimated Annual Cost Reduction ($000)
CSS Sustainability	Reduction in the sustainability costs required to maintain legacy CSS	$10,000
Mainframe MIPS[18]	Reduction in IBM mainframe processor MIPS to support the mainframe systems, retirement of Information Management System ("IMS")	$2,000
IMS Retirement	IBM IMS legacy database subsystem retirement	$700
CECONY IT Support	Reduced FTE requirements to support ongoing IT organization	$2,354
CECONY Project Support	Cost reduction to be realized by not backfilling IT project resources while they support the new CSS project	$2,891
IT Contractor Spend	Reduction in the contractor support required for legacy CSS	$2,000
IMS Headcount	IMS systems workload reduction	$275
Reduced licenses for Customer Care and Billing ("CC&B")	Reduction in the maintenance costs supporting Oracle CC&B	$221
Training Reduction	Reduction in training requirements for new employees	$2,205
Finance COA process	Elimination of Chart of Accounts ("COA") table activity[19] and associated FTE	$42
Specialized Activities	Reduction in headcount supporting specialized activities due to improved accuracy and processing capabilities in the new CSS	$725

Table 8 provides the estimated annual cost avoidance of the new CSS system.

[18] MIPS (i.e., Millions of Instructions per Second) is a measure of IBM mainframe processing speed.
[19] The COA table is a mainframe translation table bridging the accounting from the legacy CSS to Oracle. Corporate Accounting, IR/IT, and Oracle Support, spend varied amounts of time each month updating, testing, reviewing, and reconciling the COA table.

Table 8: Estimated Annual Cost Avoidance

Function	Description	Estimated Annual Cost Avoidance ($000)
Complex / Special Rates	Avoidance of future costs through cheaper and easier CSS enhancement relating to complex/special rates	$667
Future Capital Spend	Reduced future capital spend from Oracle CC&B being more configurable and easier to develop than legacy CSS	$30,799
Increase in Unbilled	A number of legacy systems currently handle complex billing structures. As the market becomes increasingly complex the number of accounts that would need to be maintained by these additional systems would continue to grow resulting in more unbilled revenues (from 8% to 10%) and a need for additional resources to manage the billing processes to maintain baseline unbilled volumes	$580
Legacy CSS Failures	Avoided cost of potential system failures associated with legacy CSS	$392
Mainframe Retirement	Cost implication of needing to maintain the mainframe due to legacy CSS remaining active.	$6,000

Benefits Summary

The benefits discussed in the previous section are projected using similar assumptions over the course of the deployment through to 2040. The estimated financial benefits during this time period are estimated at approximately $1.3 billion for CECONY and O&R.

Table 9: Estimated Financial Benefits by Category

CECONY and O&R forecasted benefits (2020–2040) *	Total ($ 000)
Cost reduction	$529,763
Cost avoidance	$727,691
Total	**$1,257,454**

*Certain IT resource benefits begin in 2020, with a majority starting in 2023

CSS Product Assessment

Given the size and the complexity of the Companies, the market for COTS solutions is essentially restricted to two vendors, SAP and Oracle, who can provide the type of comprehensive, modern platform that will meet the Companies' collective needs.[20] Based on

[20] Electric Utility Billing and Customer Information Systems – Software, Services, SaaS, and CIS-Based Analytics: Solutions Global Market Analysis and Forecasts, Navigant Research, 1Q 2015.
"CIS Trends and Implementations 2011", Chartwell, Inc., September 27, 2011

the Vendor's product evaluation approach, the Companies evaluated CSS platform options based on (1) Cost; (2) Existing footprint and knowledge; (3) Ability to leverage experience and interoperability; (4) Functionality and usability.

Based on these product evaluation criteria, the Companies selected Oracle's Customer Care and Billing ("CC&B") system for its new CSS. The Oracle technology in the new CSS is widely used by large enterprises, as well as utilities, to coordinate customer service information and billing functions.[21] CECONY and O&R already use Oracle solutions for many back office and corporate support functions including finance, human resources, and supply chain. Because CECONY Customer Operations personnel already have used a version of CC&B, certain Company employees already are familiar with the platform. This version of CC&B handles off-system complex billing algorithms for electric and gas accounts, and steam billing.

In addition, CEI, the corporate parent of CECONY, entered into a Strategic Partnership with Oracle America Inc. that includes a Perpetual Unlimited License Agreement ("PULA") in May 2018. The PULA allows CECONY to use Oracle's catalog of software applications and technologies that are used by utilities, which includes CC&B. The Companies decided that it was best to use the Oracle platform for the CSS, as it could integrate easily with the existing infrastructure and was financially optimal due to the PULA.

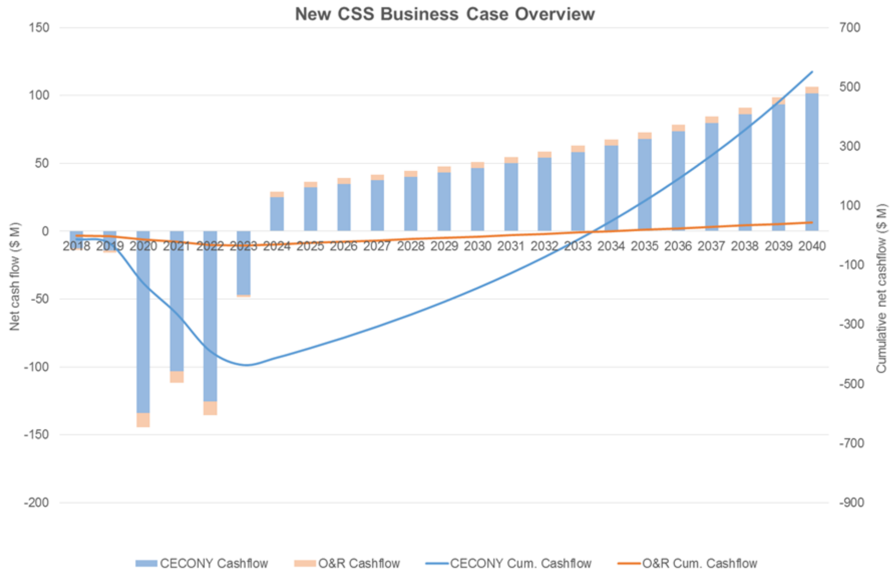
Cost/Benefit Analysis Summary and Conclusion

The chart below provides the expected benefit delivery across the life of the CC&B.

https://www.chartwellinc.com/more-utilities-look-to-replace-cis-as-system-demands-increase-market-evolves-into-competitive-landscape-for-vendors-chartwell-reports/

[21] Examples include PG&E, Oncor, Arizona Public Service,

Figure 3: NPV Calculation ($M)



This is further highlighted by the following table, which shows the net cash flow of the full deployment and benefit realization timescale, i.e., 2018 to 2040 (Table 10).

Table 10: Estimated NPV by Year ($000's)

Year	Cost	Benefit	Net Cash Flow	∑ Cash flow
2018	13,714	-	(13,714)	(13,714)
2019	18,569	2,935	(15,634)	(29,348)
2020	147,644	2,979	(144,665)	(174,013)
2021	114,675	3,024	(111,651)	(285,664)
2022	138,691	3,069	(135,622)	(421,286)
2023	71,940	23,447	(48,493)	(469,779)
2024	13,987	43,011	29,024	(440,756)
2025	8,833	45,312	36,479	(404,277)
2026	8,703	47,798	39,095	(365,182)
2027	8,589	50,229	41,639	(323,542)
2028	8,640	53,136	44,496	(279,046)
2029	8,691	56,288	47,597	(231,449)
2030	8,743	59,708	50,964	(180,485)
2031	8,796	63,421	54,625	(125,860)
2032	8,850	67,457	58,607	(67,253)
2033	8,904	71,846	62,942	(4,311)
2034	8,959	76,625	67,665	63,354
2035	9,016	81,830	72,814	136,168
2036	9,072	87,504	78,431	214,599
2037	9,130	93,692	84,562	299,161
2038	9,189	100,446	91,257	390,418
2039	9,248	107,821	98,573	488,990
2040	9,309	115,878	106,570	595,560

Conclusion

Based on the results of the Cost Benefit Analysis as discussed above, the aggregated financial benefits attributed to the implementation of a new CSS of approximately $1.3 billion by 2040 exceeds the total cost of $505 million for the platform to support both CECONY and O&R. Furthermore, the decision to replace the legacy CSS and O&R's CIMS would provide an opportunity to share in cost reductions from a shared support service arrangement, as well as provide opportunities for process standardization across both Companies. The decision also eliminates the very costly maintenance and support contracts with CECONY's current vendors, along with the higher costs associated with CECONY internal support staff. Finally, a new CSS would enable CECONY to be synchronized with O&R in terms of harnessing the latest technology to support the business and regulatory demands associated with complex billing, new products and service offerings, dynamic rate offerings and responding to increasing customer expectations. For these reasons, the Companies are moving forward with a new CSS because it is in the best interests of CECONY, O&R and their customers.

Cost Model Assumptions and Limitations

As part of the current CSS pre-implementation strategy work that started in October 2017 and continues to date, CECONY and O&R have conducted a number of activities to provide insight and assumptions used in the development of the cost and benefit forecast set out in this Business Plan. Key assumptions in our calculations are set out in the below.

Table 11: Key Cost/Benefit Model Assumptions

Assumption	Description	Source
Program labor forecast	Detailed activity based implementation plan from Envision through Deployment developed to forecast total labor hours, cost and FTE associated	Pre-Implementation Planning
Hardware and software (including maintenance)	Total estimate of all hardware and software costs (including CSS Software) required throughout the full project lifecycle	Pre-Implementation Planning
Capital and O&M allocations	All detailed cost items categorized and allocated to Capital or O&M in line with GAP-40 principles and in consultation with CECONY Regulatory, Finance and Accounting	GAP-40
Inflation	All inflation related costs and benefits impacted by compound annual 1.5% inflation increase	TBD
AFUDC	CECONY – 6.18% O&R – 2.01% Applied to all capital excluding hardware	TBD
Weighted Average Cost of Capital (“WACC”)	RY3 post-tax WACC of 6.73%	CECONY Electric Case 16-E-0060
IT Labor support costs	Detailed cost estimate for IT labor related costs associated with changes made to non-CSS systems as a result of the New CSS	Pre-Implementation Planning
Customer Operations support costs	Forecast of the front and back office impacts of a New CSS implementation and associated cost including training participation, training backfill, proficiency, transaction volumes and workarounds	Pre-Implementation Planning

IMPLEMENTATION PLAN

This section incorporates the findings through benchmarking activities conducted by the Companies on best practices for planning, developing and implementing a new CSS. In addition, the CECONY and O&R team developed an effective deployment approach and methodology for a quality system implementation, according to the project schedule, while addressing project risk. Finally, this section provides an overview of the Companies plan for change management highlighting the importance of system acceptance by the various internal stakeholders.

Benchmarking of Peer Utilities

Replacing a CSS is a major undertaking for any company. These types of projects are particularly complex for an integrated business, such as a utility, that constructs and maintains its own distribution and delivery infrastructure, and often sells more than one energy product in the regulated markets of sometimes multiple state jurisdictions. The degree of interconnectedness of the CSS with the many other business systems and applications supporting the enterprise is a key driver of the challenge. In addition to the complexity of these systems, there is a significant workload associated with the steps of planning, evaluating, selecting, implementing and testing the new systems, as well as training employees and informing customers for a smooth transition. In addition, successful projects have a high degree of executive engagement and commitment, high level of information technology competence, a deep knowledge of the company’s work processes – both current and potential future states, and proven experience with the implementation of enterprise information technology projects.

Identifying Common Challenges

CECONY and O&R contacted selected utility peers who have completed the process of implementing a new CSS in recent years. In an effort to evaluate their preparation, approaches and performances, CECONY and O&R conducted in-depth interviews, as well as site visits, to gather lessons learned from these utilities.

Table 12: Benchmark Participants

Company	Region	Utility Type	Single/Multiple Jurisdiction	Customers	Platform
Utility 1	West	Electric	Single	Over 1 million	Oracle
Utility 2	Southwest	Electric/Gas	Multiple	Over 5 million	SAP
Utility 3	Midwest	Electric/Gas	Single	Over 3 million	SAP
Utility 4	East	Electric/Gas	Single	Over 4 million	SAP
Utility 5	Southwest	Electric	Multiple	Over 3 million	Oracle
Utility 6	East	Electric/Gas	Single	Over 1 million	SAP

In addition, the Companies took advantage of shared industry knowledge related to the changing demands being placed on utility CSS, the maturation of technology solutions, and project audits that assessed root causes of the failure to implement new systems successfully.[22] What emerged from that collective work was a pattern of difficulties that caused many project challenges. Taking advantage of the opportunity to learn from the experience of others helped CECONY and O&R to prepare for the challenges of replacing CSS and CIMS. Some of the central issues the Companies and others identified as potentially problematic are:

- Executive involvement that was either distant or faded over the term of the project.
- Sponsorship of the project that was weak or diffused.

[22] Focused Management and Operations Audit of Kentucky Utilities Company and Louisville Gas and Electric Company. Final Report presented to The Kentucky Public Service Commission. Liberty Consulting Group, September 12, 2011.
Audit of Relationships and Transactions Between Public Service Electric and Gas Company and its Affiliates and a Comprehensive Management Audit of Public Service Electric and Gas Company. Final Report submitted to the New Jersey Board of Public Utilities, Overland Consulting Group, January 2012.
Final Report on an Audit of Emera Maine's Management Practices, Customer Information System, and Service Quality, Presented to the State of Maine Public Utilities Commission, Liberty Consulting Group, August 8, 2016.
Los Angeles Department of Water and Power – Consequences Linked to its Premature Launch of its Customer Information System May Push Total Costs Beyond $200 million, State Auditor of California, Report 2014-105, March 10, 2015

- Project management lacked the applicable experience and strong skills needed to establish a realistic, comprehensive and sustainable plan for the administration of such a large and complex information technology project.
- Expectations established too early in the project for the ultimate project cost, scope and timeframe, which rendered them unachievable.
- In spite of the involvement of many departments, project leadership that was often 'tilted' toward either the information technology aspect or the business processes.
- Research to identify best practices and peer-lessons learned that was either inadequate or ineffectively built into the project.
- Inventory of business requirements that was not complete or that lacked sufficient detail.
- Business requirements that were not effectively translated into a complete understanding of the application capabilities required to support them.
- The expertise and effort needed to perform comprehensive evaluations of vendors and their proposals, related to due diligence, project scope and confirmation, was insufficient.
- Customization to COTS led to increased complexity and costs.
- Implementation support from third-party contractors that had little familiarity with the systems being purchased from the software vendors.
- Inadequate code testing by the vendor prior to installation in the utility environment.
- Test environments that did not fully replicate production.
- The tendency to customize the product solution to better match the existing business processes of the organization, rather than working to implement the solution as designed.
- An organizations' resistance to re-design work processes to comport with the architecture of the new solution.
- Inadequate test team involvement.
- Inadequate training, education and organizational change management programs to help employees accept and perform competently in new work processes and systems.
- Going live with the new systems before the business was fully prepared and production ready.

- Loss of project staff after go live.
- Lack of planning and staffing Call Center appropriately post go live.

The challenges experienced by many utilities are not surprising. The process of selecting and implementing a new CSS is complex and the degree of challenge has given rise to a range of business services whose purpose is to reinforce the capabilities of companies like CECONY and O&R in the technical and project management skills identified as areas of potential weakness. Some of the key project-design decisions made by CECONY and O&R are listed below.

- Established a governance model that includes a steering committee of senior executives to provide oversight on all aspects of the design and implementation of the new CSS.
- Made the executive decision to plan for a COTS, and minimize the number of customizations. This approach, while it may demand changes be made to CECONY's and O&R's existing business processes during the replacement, helps customers benefit from the periodic application updates to be provided without bearing the cost of the additional software programming that would otherwise be required to accommodate the volume of customized computer code.
- Established a CECONY and O&R CSS project leadership structure with Project Co-Directors serving as executive leaders of the effort: (1) the Project Director, responsible for the overall project, (2) the Director of CIMS for CECONY and O&R business processes and integration and (3) the Director of IT responsible for the information technology aspects. The intent of this structure was to overcome a common failing of projects to 'overweight' one aspect of the project (*e.g.*, the technical) to the detriment of the other (*e.g.*, the business). In addition, these resources are dedicated full time or a portion of their time to the CSS project.
- Hire an outside subject matter expert in change management to work on developing and implementing a communications/change management plan for the project. Benchmark participants suggested this function was critical to substantially change work processes that accompanied the adoption of off the shelf applications.
- Develop Requests for Proposal to fully develop and implement the CSS.

- Verify that the vendor selected for supporting the implementation of the customer service has direct experience and extensive familiarity with the CSS application selected.
- Retaining an outside project manager with significant expertise and experience implementing enterprise-wide utility software applications – being assigned the broad responsibility for the overall implementation process, including the coordination of project leaders representing the vendor applications selected and those who would be selected for quality assurance monitoring and system testing.
- Identifying and securing the full-time participation of key employees who would be needed full time for the project.
- Securing dedicated office space located away from the distractions of day-to-day operations, and having ample office and meeting space for all project leaders, employees and contractors associated with the project.
- Retaining the services of an outside firm specialized in developing training programs for new systems, development of the curricula, training the trainers, and evaluating the effectiveness of the training effort.
- Planning an employee communication and readiness program that would be part of the O&R and CECONY change management effort for the new CSS project.
- Anticipating the service changes that would arise for customers associated with the new CSS, and planning the communications effort that would accompany the "go-live."
- Focusing on data conversion at the onset. The quality of the converted data has a large impact on the number of exceptions encountered upon go-live. Several utilities also cited testing to the extent that they had a good feel for the impact of process changes and change management work that would be required upon go-live.
- Focusing on having the right number of environments for all phases of testing to reduce frequency of delays and improve development cycle times.

Deployment Approach and Schedule

The CSS project is estimated to take three and a half years to implement with additional O&M investment beyond the four month stabilization period. CECONY and O&R use a

Software Development Life Cycle ("SDLC") approach that allows for software to be developed in a robust and repeatable manner. The SDLC process includes various methodologies such as Waterfall, Agile and Iterative. The Company requires that widely accepted methodologies be used for the deployment of system projects. For this project, CECONY and O&R will use a Waterfall methodology that includes Envision (including Project Management activities), Plan, Build, Stabilize, Deploy and Post "Go Live" Support. The following is a brief description of each phase.

- **Envision**: One of the guiding principles will be to develop synergies and promote standardization where applicable between CECONY and O&R. The strategy will be used to inform, add or modify any requirements. The team will map existing requirements to the identified key processes for downstream and upstream traceability. This exercise will help to determine the high-level target state to be achieved. The deliverable will include the selection of a CSS software platform and systems integrator, which will guide future efforts. Furthermore, a set of go-live criteria will be established to inform go/no go decisions at point of system cutover and go-live. The project is currently in the "Envision" phase that is expected to be completed at the end of 2020.

- **Project Management**: Project management activities will focus on detailed planning of the new CSS, including building the detailed work plan, identifying and documenting project assumptions and risks, refining the high level solution scope and requirements and establishing the approach, technique and tools to support solution-requirement traceability throughout the project lifecycle. In addition, this phase will support onboarding project resources and define how to organize the project governance structure. Once the detailed planning is completed, the Companies will develop appropriate staffing plans for every activity identified in the detailed planning process so the appropriate people and skills can be on-boarded. This work is expected to take the duration of the project.

- **Plan**: During the Plan phase of the project, the detailed business process flows will be broken down into more granular individual activity and steps to determine how the process changes should be designed to support the defined To-Be business processes. The functional designs developed and reviewed during the Envision phase will serve to develop the technical designs for each process change. In parallel, the project infrastructure, environments, and tools will be set up and the technical architecture will be designed to meet the technical, security, and performance requirements. To prepare for the Stabilize phase, functional analysts will start to document test cases and scenarios, to be further refined and detailed in the next phase. These will feed into the overall test effort during Stabilize phase. This phase, some of which take place during Envision, is planned to take 12-15 months to complete.

- **Build**: The Build phase of the project will begin by refining the customization (as necessary), integration, and data conversion designs until they are concrete and detailed enough to be built. At this point, each of the process changes will be developed and areas of the solution that require configuration of the packaged software will be built. Technical environments and production infrastructure are also established. In anticipation for the Stabilize phase, test scripts, test cases, and scenarios are further developed, and tracked against expected test results. This phase is expected to take ten months to complete.

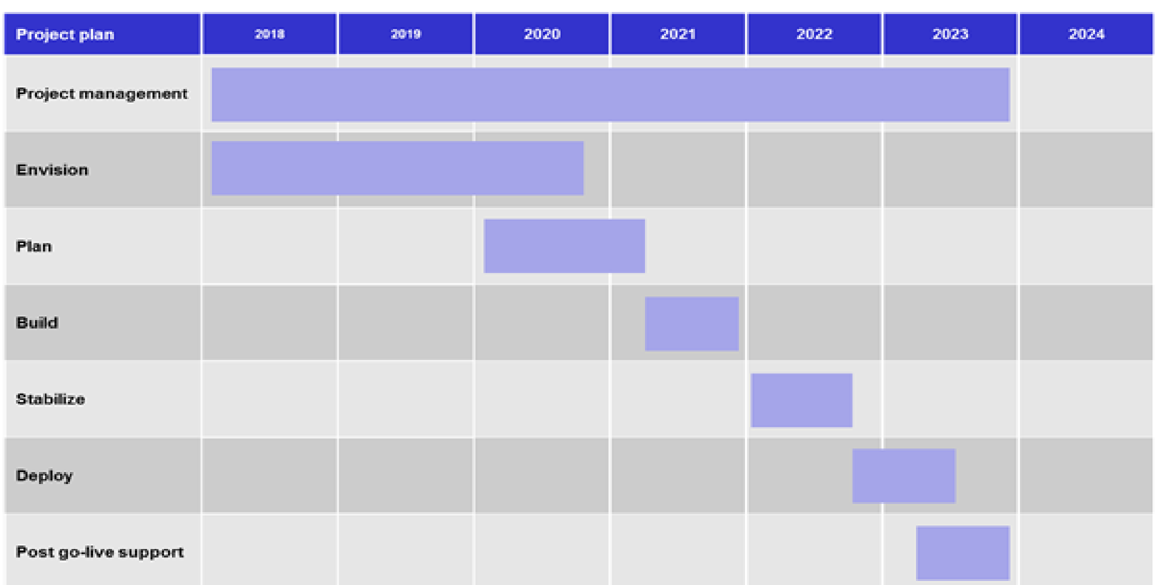
- **Stabilize**: During the Stabilize phase, every aspect of the solution will be tested so that the end-to-end product works as expected. The team will prepare and execute the performance test and perform the mock data conversion to test the conversion process. The last step in the Stabilize phase is the completion of User Acceptance Testing, in which the process or business users test the product so it meets the requirements previously established for their functional areas. Training also begins during this phase so that future system users are given the foundational knowledge required to perform their day-to-day activities, limiting the impact of deploying a new system on the operations. The phase is expected to take 11 months to complete.

- **Deploy**: Once the system is fully tested, the project will enter the Deploy phase and the effort can shift from building and testing the solution to placing it into service. This occurs through a cutover process, where production is moved from the legacy CSS to the new CSS. At this point, the legacy system can be taken out of service and the new system is rolled out to the workforce and deployed. Training will continue to be rolled out during this phase, to help minimize the impact to operations and properly adopt the target business processes. Deployment is expected to take approximately six months to complete, leading up to "go live" in the summer of 2023 for CECONY and O&R.

- **Post "Go Live" Support**: This phase of the project will focus on two main areas. The first will be verifying that the new CSS performs as expected, from a technological and operational standpoint. Any system issues or defects that may arise once the system is live will be addressed and resolved during this phase. In addition, this phase will extend beyond the "go-live" date to support operations as the new system is deployed. To safeguard against potential negative impacts to operations, Staff Augmentation resources will be brought in to alleviate potential negative impacts to operations, such as increases in call volumes, call handling times, and billing exceptions (see Labor Plan for details).

The Build phase of the new CSS will begin in April 2021 with a completion, or go-live date, in summer 2023 for CECONY and O&R. CECONY and O&R are presently in the Envision Phase defining the high level vision, plan and business case. The costs and scope in this Business Plan reflect the analysis performed during this Phase of the project. A high-level project schedule is provided below.

Figure 4: Proposed CSS Platform Development and Implementation Schedule



Risk Management Plan

Our risk management plan details the elements of the risk management process. This process comprises four phases - Risk Identification, Risk Assessment, Risk Handling, and Risk Monitoring.

Risk Identification

Risk identification is the process of examining the project areas and each critical technical process to identify and document the associated risk. The identification of potential issues, hazards, threats, vulnerabilities that could negatively affect work efforts or plans is the basis for the risk management strategy. The project will use the following methods for identifying risk:

- Examine the work breakdown structure ("WBS") to uncover risk areas;
- Interview subject matter experts;
- Examine lessons learned documents;
- Examine design specifications for product enhancements, interfaces and reports;
- Review project management and implementation strategies;
- Conduct risk assessment and risk management reviews; and
- Continuous identification of risks on all project workstreams.

Identifying cost, schedule and performance risks takes place during the startup phase and continues throughout the project's life cycle. Cost risks may include those associated with funding levels, funding estimates and distributed budgets. Schedule risks may include risks associated with planned activities, key events and milestones. Performance risk may include risks associated with applying new technology (*e.g.*, an upgrade to a newer product version), resources (*e.g.*, availability of people), or functional performance and operation of the product.

Individual team members involved in the detailed day-to-day technical, cost and scheduling aspects of the project are the most aware of the potential risks that need to be managed. Both the selected project management vendor and the Companies' project team will reiterate the importance of identifying these potential risk sources. Part of the risk assessment process will be to survey the team members for potential risk events and circumstances. The process accumulates and documents information on events or circumstances that will be evaluated to determine any potential adverse impact on the project from a technical, cost or schedule viewpoint.

Risk Assessment

Risk assessment is the process of analyzing known risks and prioritizing them based on their threat in attaining project goals. Throughout the project, each risk will be analyzed to isolate its cause and to determine its potential effects. The project team rates the risk in terms of its probability of occurrence and its severity of impact to cost, schedule and technical performance, as applicable.

The probability of a risk is the chance that the risk will materialize as a "real project issue." This probability can be expressed in quantitative or qualitative terms. The risk impact measures how the project is affected if the risk materializes. Qualitative assessments may be used as an initial filter, but all high and medium risks will be assessed quantitatively.

Risk Handling

Risk handling is the process that identifies, evaluates, selects and implements options to set risk at acceptable levels given project constraints and objectives. This includes the specifics on what should be done, when it should be accomplished, who is responsible, and associated cost and schedule. This will be implemented in line with the project governance structure to manage all risks and issues effectively.

The most critical component of risk handling is the development of alternative courses of action, work-arounds and fallback positions, with a recommended course of action for each critical risk. Options for handling risks will include the following alternatives:

- Avoid risk by changing or lowering requirements, while still meeting user needs; usually taken if either organization cannot afford to lose, or the exposure to the outcome is too great, or a large number of alternatives exist (and a greater uncertainty);
- Mitigate risk by taking active steps to minimize the risk;

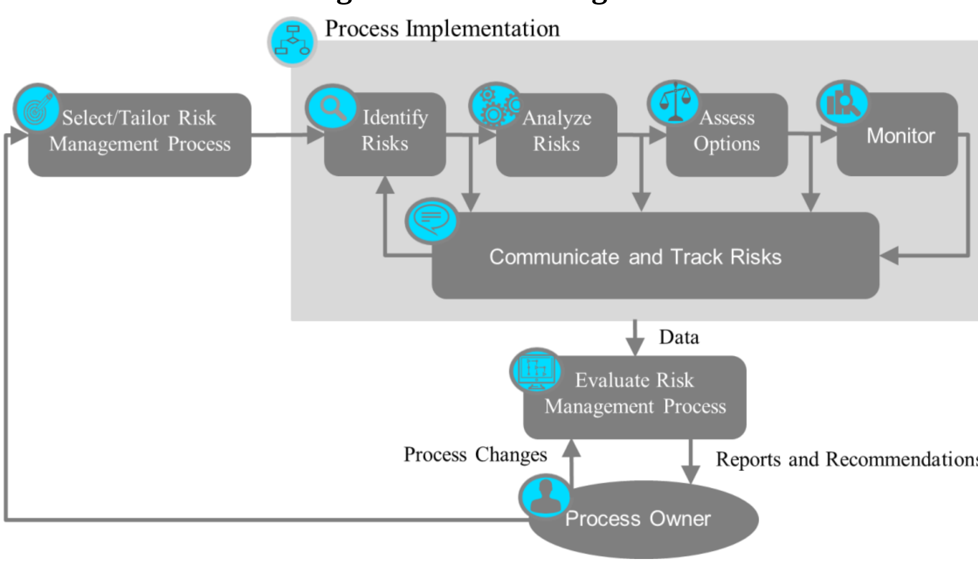
- Transfer risk by sharing the risk with others or transferring the risk entirely to others;
- Monitor risk by watching and periodically re-evaluating the risk for changes to the assigned risk parameters; and
- Accept risk by acknowledging the risk but not taking any action.

Risk Monitoring

Risk monitoring is the process that systematically tracks and evaluates the performance of risk-handling actions against established metrics through the project and develops further risk-handling options, as appropriate. To control and manage risks effectively during the work effort, the project regularly monitors the risk and the status/results of risk-handling actions. A risk register will be developed to track each risk-handling activity on this project and will be updated throughout the project in order to identify and manage risks continually. In addition, information on risks will be included in the monthly project status report and discussed at the respective governance committees.

The risk management process as described above is depicted in the following diagram:

Figure 5: Risk Management Process



CSS Project Governance

For the purposes of the new CSS, project governance is the structured system of rules and processes used to administer the CSS planning and implementation effort. The governance model for the CSS project has a decision-making framework to foster accountability and alignment between the project team, executives, and other stakeholder groups. The CSS governance model was developed to facilitate project delivery on time and on budget by bringing together stakeholders for efficient decision-making, with a focus on key decisions that not only shape the project, but the project direction, and mitigation of risk.

The CSS project team has adopted the governance model to highlight a clear distinction between project management and project governance. The distinction between project management and governance is in focus and intent. Project management is the application of knowledge, skills, tools, and techniques to project activities to meet the project requirement, where project governance is less about the details, and more about the conditions that set up the project and are outside the project's boundaries. The approach used for CSS governance model is described below. The graphic demonstrates focus of CSS governance, project management and how the model is mobilized.

Figure 6: CSS Governance Approach

Project governance

- Enables alignment across complex Projects and transactions
- Provides a single point of reference for planning, priorities and risks to drive desired outcomes
- Provides structure, governance and clear roles and responsibilities across the project to ensure that the joint effort stays focused on delivering value
- Provides oversight and control to support risk management across the project for leadership team

Project management

- Manage week to week task and work plan delivery and oversight across all workstreams
- Implement standardized approach to managing risks, issues, decisions and dependencies
- Manage project finance delivery, tracking and forecasting
- Executive and operating steering committee briefings/presentations

Mobilization

- Senior leadership review and approval of all recommendations
- Establish and integrate recommendations into project
- Stand up required governance structures and process (as required)
- Continually review effectiveness and iterate as required to support delivery

The project governance and decision making framework outlines who has responsibility and authority to make decisions, so that there is clearly defined accountability for all aspects of the project. It is the link between, and support for, the governance decisions made by the Executive Committee and the work of the Project Leadership team to deliver the project and its outcomes. A sound project governance decision framework provides for a shared understanding of governance roles and the investment parameters, scope and deliverables.

Organizational Change Management

In the context of CSS implementation, the purpose of Organizational Change Management ("OCM") is to engage and prepare the end users, business partners, internal and external customers to use the new CSS in such a manner as to:

- Realize the benefits of the new processes and functionality;
- Reduce the impacts of decreased Day 1 "post go live" operational efficiency and impact on customer service;
- Reduce the effort required to address work-arounds and temporary activities; and
- Mitigate negative impacts.

To achieve these objectives, CECONY and O&R will engage an OCM services partner to advise the Companies in the development and execution of a structured and collaborative change management program leveraging industry leading practices and toolkits. The OCM workstream will design an approach tailored to a utility oriented CSS implementation that focuses on enabling and engaging employees to perform their jobs effectively and efficiently.

Labor Plan

The labor plan developed presents an encompassing view of the staffing levels required throughout the project lifecycle. This will include CECONY and O&R internal resources to support the project and operations, as well as external resources and associated skillsets required for large IT projects. The resource sourcing mix considered several factors, including: (1) availability of resources with the required internal project skillset within IT and Customer Operations, (2) alignment of IT managed-service-provider expertise with project activities, (3) System and Business Integrator critical roles to support the objective of minimizing project risk, and (4) previous CSS implementations in the industry.

CECONY and O&R Staffing

To incorporate knowledge of CECONY and O&R business and IT operations into the solution design, it is critical to include the Companies' subject matter experts throughout the project phases. These internal resources will play many key roles in the Envision, Plan, Build, Stabilize and Deploy phases, including but not limited to:

- Functional Designers to define the current (As-Is) and target (To-Be) processes;
- Subject Matter Experts to support the definition of the current (As-Is) and target (To-Be) processes;
- Technology and Solution Architects to manage technical resources;
- Integration Coordination to support the integration of the new solution with existing and retained peripheral systems;
- Organizational Change Management to prepare the organizations for the transition to the new CSS;
- Developers to assess, design, and build the new CSS;
- Data Conversion to support the translation of current legacy-system data to be compatible with the new CSS data model;
- Test Execution to support the planning and designing of the testing materials, including test scenarios and test scripts, which will be used to test the new solution; and
- Training for sufficient level of proficiency in the new CSS to embed knowledge and improve comfort levels with the new way of working as the Companies approach go-live.

In line with industry benchmarks, CECONY anticipates 40 percent of CSS project staffing to be delivered by CECONY and O&R resources.

External Resources

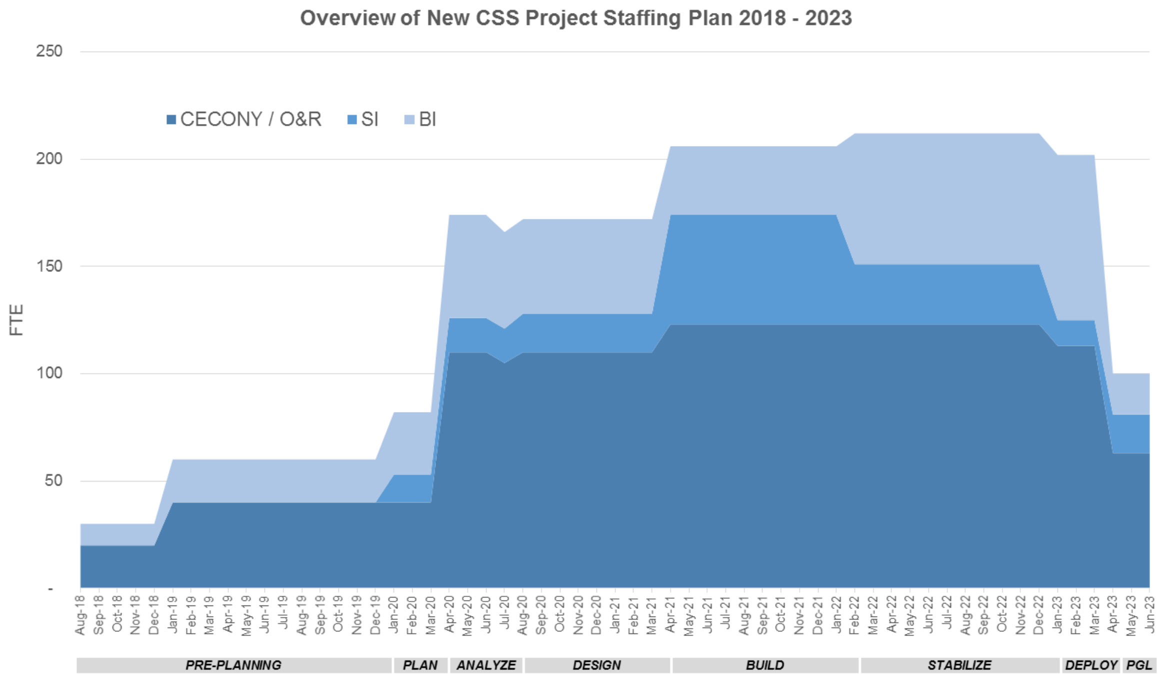
The staffing plan assumes a sourcing mix between CECONY and O&R and external labor. As per industry best practice, large scale IT implementations are usually undertaken in partnership with third-party contractors. These resources provide specialized expertise on the CSS platform being implemented and assist in designing, configuring, and testing the solution. These external resources will play many different roles in the new CSS implementation, including but not limited to those described below.

- System Integrators (“SI”) and other consultants to advise and support on how best to plan and realize an implementation of this magnitude. Their proven methodologies, experience, and lessons learned will support each phase of the implementation by providing relevant frameworks, guidance, and support to the CECONY and O&R project team. CSS product knowledge, IT project implementation methodology, industry standards, and best practices are just a few of the foundational elements required for CECONY and O&R to implement a CSS solution successfully.

- Software vendors to provide product-specific expertise to support the integration between those products and the other systems they will interface with, as well as to support core design, configuration, and development activities.
- Managed service providers who currently support the legacy technology portfolio, to provide knowledge on the current IT landscape and the integration points between the legacy technology portfolio and the new solution. These resources will also be assigned certain development and configuration roles. This pool of resources may be located offshore or on the project premises.
- Staff augmentation resources to assist in the Deploy and Post "go live" phases of the project. These resources will help alleviate potential negative impacts to operations associated with introducing a new solution (*e.g.*, Call Center operations). They will assume training, front-office, and back-office support roles throughout the Deploy and Post "go-live" phases.

Figure 7 below illustrates the draft overall staffing plan for the project through Post Go Live Support, excluding customer operations and non-project related IT resources.

Figure 7: New CSS Project Team Staffing Plan



Data Protection and Personally Identifiable Information ("PII") Plan

There have been recent breaches of PII involving large companies. Equifax suffered a breach that affected 143 million consumers – including the exposure of Social Security numbers and driver's license numbers.[23] CECONY and O&R understand the risk of PII and sensitive information loss, and works to continuously improve the processes, systems, and controls to mitigate this risk.

Data Protection and protection of PII are critical components to the success of the CSS pre-implementation project. In this regard, there is no "one-size fits all" when it comes to establishing and maintaining a robust security program to address the need to protect customer data. The CECONY and O&R approach is based upon the key principles of balancing risk and cost, and identifying threats and gaps for strategic prioritized investments to address business needs and risks with the intent to increase the value of information security activities to the organization, while keeping the Company's IT assets and customer data more secure. The current data security program is built upon the following framework:

[23] http://time.com/5234740/facebook-data-misused-cambridge-analytica/ . https://www.forbes.com/sites/nickclements/2018/03/05/equifaxs-enormous-data-breach-just-got-even-bigger/#db024b353bc5

Table 13: Data Protection and PII Framework Summary

Domain	Practices
Governance	There is a hierarchy of four governance committees providing data protection and PII oversight. **Security Executive Team**
	Corporate Cybersecurity Team
	Breach Response Team
	Privacy and Data Protection Working Group
Key Policies and Procedures	**CEI-211 "Protection of Personally Identifiable Information (PII)",** July 2018 – Provides instruction and assign responsibilities for protecting personally identifiable information (PII) and provides guidance for reporting and responding to a potential incident when PII is disclosed without authorization. **CEI-407 "Data Classification"**, October 2018- Provides the basis for protecting the confidential information of the Company or in the Company's possession by establishing a data classification policy and process.
Monitoring	Annual audits by internal and third party per requirements of the NYPSC. User and administrator access controls reviewed for systems that house sensitive data. Compliance processes with record retention and final disposition of PII
Awareness	Developed training and awareness materials on PII, including an e-learning module
Data and Network Security	Implementation of Data Minimization and role based access controls. The general concept of least privilege access is applied to the design of all systems. Users are provisioned to applications and resources that house sensitive data based on position/work needs. A 24/7 Security Network Operations Center monitors and responds to cybersecurity and privacy issues.
Third Party Access	Data minimization principles are applied for 3rd party data requests. The Company assesses each request so that only the required information is provided via secure channels to approved third parties, thus mitigating loss of sensitive information
Incident Response	Documented Risk Event Guide, detailing the data breach response process noted in CEI-211.

In accordance with this framework, CECONY and O&R will continue to follow corporate policies and procedures to evaluate and enhance data protection processes and controls to mitigate an evolving threat landscape and an increasing risk of data loss. This data governance and data security program will drive the design and deployment of security and privacy controls surrounding the implementation of the new CSS.

CECONY and O&R business application assets are protected by security controls, including those designed for information in databases and accessible through software applications, built into the applications during system design and implementation through the

SDLC process. Key governing principles applied to new systems following the SDLC process include:

- Architecture reviews of procured systems for proper design and incorporation of security controls;
- Secured coding principles utilized for developed applications;
- Role based access controls implemented throughout the system;
- Systems designed so that data flows follow data pull techniques from "High Trust" to "Lower Trust" networks; data is never to be pushed into "High Trust" from "Low Trust" networks;
- External data exchanges are encrypted to protect information transmitted between business applications and external organizations; and
- Authentication techniques used by users and system components.

The new CSS implementation will adhere to these principles to protect customer PII.

Recently, CECONY and O&R completed a data protection assessment with the objective of understanding sensitive data elements within the current CSS system to determine the following:

- Data protection requirements and drivers necessary to protect these data elements in the new CSS application; and
- Translate business requirements into technical and functional requirements to be used as a requirements baseline for the new CSS.

Through the implementation of a new CSS, CECONY and O&R seek to streamline access controls and authentication improvements using Active Directory and two-factor authentication solution. In addition, CECONY and O&R seek to separate and segment the new CSS from the existing corporate network to mitigate risk of a data breach as well as take advantage of encryption tools to protect PII. Finally, CECONY and O&R expect the new CSS to contain enhanced event logging and proactive monitoring functionality for audit, investigation and remediation purposes. CECONY and O&R expect that with a modern platform, the Companies will be better prepared to protect against emerging threats and mitigate issues quickly.

While CSS technology vendors may address data protection within their solutions, the CECONY and O&R vision is to implement common controls to protect customer data that provides a holistic enterprise wide view that is risk based, technology and business focused, and considers other factors which could potentially lead to the increased risk of a data loss scenario.

PERFORMANCE METRICS

The following section provides a brief summary of project performance metrics and example “go live” criteria that will be tracked during the implementation of the new CSS.

Project Management Metrics

Project management is a continuous review of how effectively a team employs the management tools and metrics that are available to direct and control project cost and schedule performance.

- **Project Cost Performance** – Project cost accounting is a necessary tool in the oversight and control of project cost performance as it captures, monitors, and reports on the monetary status of all cost-related activities. Monitoring and analysis of the work execution compared to the cost baseline is the foundation for effective corrective action. Through the use of appropriate cost control methods and systems, cost “surprises” can be minimized and the project management group is provided the information needed to understand the nature of cost issues and conditions.
- **Project Schedule Performance** - Project schedule management is used to establish target start and finish dates and monitor performance. In order to establish the ability to monitor schedule performance, the CSS project team will determine the proper sequence and phasing of all proposed work and identify important milestones. Once this is structured, CSS project team will develop a framework to collect data on the progress of work by all work streams, indicate the status of the CSS project against key milestones, and provide information on the progress of individual work streams. In the event of changes to the implementation work, the CSS project team will be able to determine the schedule impact of both proposed and actual changes, using the scheduling system to indicate possible solutions for schedule recovery.

Examples of project management metrics are provided in the table below:

Table 14: Example Project Management Metrics

Metric Group	Metric
Project Cost Performance	• Project Cost Variance (budget v. actual) • Change Control Metrics (approved v. rejected)
Project Schedule Performance	• Schedule Adherence • Project Hours Variance (planned v. actual) • Project Milestones (*e.g.*, Functional Design Completion, Technical Design Completion, CSS Build Completion, CSS Testing Completion)
Earned Value	• Cost Performance Index • Schedule Performance Index

A final set of project management metrics will be established during the Envision phase.

Go-Live Criteria

In addition to the project management metrics, there will be pre-defined set of go-live criteria. The criteria are intended to mitigate post-go live issues and reduce overall customer impact. Examples of go-live criteria are noted in the table below:

Table 15: Example CSS Go-Live Criteria

Group	Criteria
System and Performance	Application security has been tested and is ready for Go Live. The system is stable and performing at an acceptable level after a cycle of performance testing. Interfaces are functional.
Conversion	Data refresh process has been rehearsed multiple times, data quality and accuracy is accepted by the business users; testing was completed.
Testing	All testing cycles are completed.
Organizational Readiness	Overall IT and Business is ready for operation. End User Training is complete. Roll back plan is in place.
Bill Customers (accurate and complete)	Ability to print accurate billing with all calc lines; customers can view the bills online.
Customer Activities	Ability to perform key customer activities *i.e.* start and stop service.

A final set of go-live criteria will be established during the Envision phase.

LIST OF ABBREVIATIONS

AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
CC&B	Customer Care & Billing system (Oracle CSS product)
CECONY	Consolidated Edison Company of New York, Inc.
CIMS	Customer Information Management System
COA	Chart of Accounts
COBOL	Common Business-Oriented Language
COTS	Commercial Off-the-shelf system/solution
CSR	Customer Service Representatives
CSS	Customer Service System
CUBS	Consolidated Utility Billing System
DCX	Digital Customer Experience
DSP	Distributed System Platform
EDAP	Enterprise Data Analytics Platform
EE	Energy Efficiency
ESCO	Energy Service Company
FTE	Full Time Equivalent
GAAP	Generally Accepted Accounting Principles
GAP	General Accounting Procedure
IOU	Investor Owned Utility
IT	Information Technology
NorthStar	NorthStar Consulting Group
NPV	Net Present Value

NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
OBR	On-Bill Recovery
OCM	Organizational Change Management
O&M	Operations and Maintenance
O&R	Orange and Rockland Utilities, Inc.
PII	Personally Identifiable Information
PULA	Perpetual Unlimited License Agreement
RAMIS	Random Access Management Information System
REV	Reforming the Energy Vision
SDLC	System Development Life Cycle
SI	System Integrator
WACC	Weighted Average Cost of Capital
WBS	Work Breakdown Structure

	Capital
X	O&M

2020 – Customer Energy Solutions

Project/Program Title	Advanced Metering Infrastructure (AMI) Common O&M
Project Manager	Thomas Magee
Hyperion Project Number	21125226 (L1)
Status of Project	In-Progress
Estimated Start Date	2/2015
Estimated Completion Date	2022
Work Plan Category	Strategic & Regulatory Required

Work Description:

Con Edison is currently deploying Advanced Metering Infrastructure ("AMI") across its service territory until 2022 as approved by the Commission. The scope of work for this project includes the following:

1. Building the AMI Information Technology ("IT") platform and developing the system interfaces between the AMI IT platform and legacy applications.
2. Installing the AMI communications network for territory-wide coverage.
3. Installing approximately 3.6 million electric smart meters, retrofitting 950,000 gas meters with AMI modules, and replacing approximately 230,000 gas meters with meters equipped with AMI modules (these 230,000 include tin case gas meters that cannot be upgraded with a new meter and AMI module, and meters that need to be remediated due to performance).

For details on the Company's AMI Project, please reference the following documents:

- AMI Business Case filed in November 2015[1]
- *Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions*[2]
- *Order Approving the Electric and Gas Rate Plans*[3]

The AMI Program has introduced new IT infrastructure to the Company. As such, implementation and ongoing maintenance expenses are being incurred to maintain the new systems. The AMI Project O&M expenses are annually recurring to maintain the AMI systems and communications infrastructure. In addition to the Project's expenses, other O&M funds will support the mandated AMI Customer Engagement Plan, which was required under the AMI Order. For the full scope of details on the AMI

[1] Case 15-E-0050, Consolidated Edison Company of New York, Inc. – Electric Rates, *CE AMI Business Plan* (filed November 16, 2015) ("AMI Business Plan").
[2] Case 15-E-0050, Consolidated Edison Company of New York, Inc. – Electric Rates, *Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions* (issued and effective March 17, 2016) ("AMI Order").
[3] Cases 16-E-0060 and 16-G-0061, Consolidated Edison Company of New York, Inc. – Electric Rates and Gas Rates, *Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal* (issued and effective January 25, 2017).

Project's Customer Engagement Plan, please reference the document filed with the Commission on July 29, 2016.[4]

<u>Justification Summary</u>:

The AMI Program O&M expenditures occur in two main categories: AMI project and Customer Engagement O&M expenditures. The AMI Project O&M expenses are annual recurring expenses required to maintain the AMI systems and communications infrastructure. The O&M Customer Engagement expenses cover the AMI deployment period and may be extended as engagement activities continue beyond implementation as needed.

The table below summarizes O&M costs for the AMI Program:

[4] Case 15-E-0050, Consolidated Edison Company of New York, Inc. – Electric Rates, *Advanced metering Infrastructure Customer Engagement Plan* (filed July 29, 2016), ("AMI Customer Engagement Plan").

O&M Cost Categories and Descriptions

O&M Category	O&M Description
AMI O&M: AMI Labor	• IT and Operations Support • Includes O&M labor associated with maintaining the various AMI systems and running the Operations Center
AMI O&M: Software Maintenance and Hosting	• Software maintenance, licenses, and hosting costs associated with the AMI IT platforms for MAMS (Meter Asset Management System), MDMS (Meter Data Management System), HES (Head End System), EDAP (Enterprise Data Analytics Platform), etc.
AMI O&M: Communications	• Core AMI infrastructure, including site lease costs associated with installing communications devices on non-company owned infrastructure • AMI communications costs
Customer Engagement: Customer Education	• All work related to AMI customer external outreach • Includes, but not limited to: AMI focus groups, surveys, AMI outreach education materials, including AMI direct mail notifications for 3.6 million customers, mailers with energy reports and alerts, door hangers, AMI events including a minimum of two events per region annually over the remaining deployment period
Customer Engagement: Rate Pilot	• Identify how innovative rate structures can enhance customer benefits of the AMI system in a cost-effective manner. • Main objectives: ○ Gauge customer acceptance of alternative pricing for delivery service and their response to such prices, including changes in usage, peak demand, and total electricity bills; ○ Determine whether and how changing the pricing of delivery services will affect customer behavior (and thus their usage and peak demand) to drive more efficient use of the electric distribution system; and ○ Provide data and information that can help estimate the customer benefits resulting from alternative pricing of delivery service. • The pilot findings will be used to provide support in estimating customer benefits derived from the introduction of AMI. Moreover, the findings and lessons learned during the pilot will be used to inform future mass market rate design reform.
Customer Engagement: New Revenue Opportunities	• The Company is evaluating opportunities to leverage the AMI network by working with third parties that can reduce costs or generate new revenues. • Activities will also seek to identify and propose a framework under which third parties can participate in an opportunity utilizing the AMI network; this framework would include a process for identifying, measuring, and sharing savings from such efforts.

Total O&M costs anticipated to be incurred during the rate period to support the AMI Program and Customer Engagement activities are estimated to be $145 million from 2020 – 2022. The table below summarizes the O&M costs for the rate plan. O&M will increase slightly from 2020 to 2021 to cover labor costs and software maintenance as AMI systems and network go into service. From 2021 to 2022, O&M will stabilize for ongoing AMI expenses and decrease for Customer Engagement activities, yielding a net decrease in 2022.

AMI Program O&M Costs - $M

AMI O&M Requirements	**$M**	**Request**	**Request**	**Request**
Year	**$M**	**2020**	**2021**	**2022**
AMI Project O&M	AMI Project O&M	$36.13	$42.14	$41.18
Customer Engagement	Customer Education	$5.80	$5.50	$2.70
Customer Engagement	Rate Pilots	$3.00	$3.30	$1.40
Customer Engagement	NRO	$1.20	$1.20	$1.20
Total Requested	Total Requested	$46.13	$52.14	$46.48
Incremental Request	From Test Year $18.53	$27.60	$6.01	$(5.66)

Supplemental Information:

Alternatives/No Action/Delayed Action:
Summary of Financial Benefits (if applicable) and Costs:
Technical Evaluation/Analysis:

The Con Edison AMI Project was approved by the Commission in the AMI Order, which included a review of the AMI Business Plan.

Basis for Implementation Estimate:

The basis for the O&M costs associated with the AMI Project considers what is needed to run the AMI systems during and after deployment. The labor cost estimates were derived from average salaries of employees and number of employees that are required to support the AMI systems and deployment, applicable overhead rates for costs associated to maintaining the systems, etc. (i.e., taxes, etc.), work performed on the project, and yearly inflation. Cost estimates for the maintenance and hosting fees were extracted and extrapolated from current negotiated contracts with the AMI IT system vendors, and software components were prepared by subject matter experts ("SMEs") in the Company from the IT organizations working with the AMI Team. Communications costs and Revocable Consent fees were derived from negotiated rates and estimates were made on communications site leases. Customer engagement activity costs were compiled based on SME negotiated contracts, average salaries of employees, number of employees that are required to support the effort, and discussions with potential vendors to complete the work scope identified in the Customer Engagement Plan.

Annual Funding Levels ($000)

Historical Elements of Expense

EOE $K	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Actual 2018**
Labor			**$4**	**$1,164**	**$4,094**	**$4,554**
M&S						
A/P						
Other			**$324**	**$6,169**	**$14,439**	**$15,396**
Overheads						
Total	**N/A**	**N/A**	**$328**	**$7,333**	**$18,533**	**$19,950**

Future Elements of Expense

EOE $K	**Budget 2019**	**Request 2020**	**Request 2021**	**Request 2022**	**Request 2023**
Labor	**$5,300**	**$8,610**	**$12,260**	**$13,920**	**$16,062**
M&S					
A/P					
Other	**$29,800**	**$37,520**	**$39,880**	**$32,560**	**$33,238**
Overheads					
Total	**$35,100**	**$46,130**	**$52,140**	**$46,480**	**$49,300**

Note:

1. *The O&M funding request for the mandated Customer Engagement Plan is also included in this filing request.*
2. *At the end of the AMI implementation in 2023 the project expenses will be allocated to IT and operating organizations where appropriate.*

	Capital
X	O&M

2020 Customer Energy Solutions

Project/Program Title	Innovation Initiative
Project Manager	Josh Gould
Hyperion Project Number	N/A
Status of Project	In-Progress
Estimated Start Date	Ongoing
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

Con Edison recognizes that a strong organizational capability for innovation is critical to facilitating the transformation of the electricity system and in achieving REV objectives as described in REV Track One Order. The Company is establishing a corporate-wide Innovation Initiative to strengthen our existing capability to identify and facilitate the development of transformative innovation projects. The initiative complements and builds upon the Company's existing innovation efforts, REV Demonstration Projects and Research and Development ("R&D"). The Innovation Initiative establishes an innovation center of excellence to guide innovation project development and governance ("Innovation Hub") and creates a funding mechanism for these projects separate from the originating department's operating funds ("Innovation Common Fund").

To achieve lasting impact through innovation, the Company has designed an approach that expands upon existing innovation efforts being carried out through the Company's REV Demonstration Projects and through the Company's traditional R&D efforts. Con Edison's R&D team tests novel technological solutions in early-stage research and product development, with a focus on technology that has the potential to provide core operational and safety value. The results of R&D projects are typically prototypes that do not go into commercial, productive use, but rather provide the underlying specifications for purchase orders of new equipment to be built by third-party manufacturers for procurement by various Company operating departments. REV Demonstration Projects develop and test new business models and revenue streams, including measuring customer response to programs and pricing, and developing and testing DSP technologies and practices.

The Innovation Initiative will evaluate projects that have successfully completed an R&D effort, or originate from other departments within the company and show potential for wider commercial impact but do not warrant development into a Demonstration Project, or do not have a natural home in any single business operating group. A small team of Innovation Hub employees will lead the effort to identify innovative ideas with the potential for growth, and provide support and oversight of the initiatives targeted.

The Innovation Hub is designed to coordinate innovation throughout the Company through:

- Initial Idea Surfacing: Through close coordination with R&D, REV Demonstration Projects and other internal operating departments, the Innovation Hub will work to develop innovation ideas that do not quite fit into defined product/concept development pathways.
- Innovation Idea Development: The Innovation Hub employees will work with innovation owners to better understand business potential and applicability of the concept. Once an idea has been

developed, it is presented for approval to an Innovation Council consisting of Con Edison senior executives. Innovations that are not approved are either further developed based upon executive feedback or are returned to the originating department for local use.

- Coaching and Planning: Innovation Hub employees provide guidance and coaching to the innovation owners as a plan is developed for wide-scale deployment. Any funding required to provide resources for subject matter experts for third-party support teams (e.g., IT, contract services) to facilitate the development and testing of the ideas would be provided by the Innovation Common Fund.
- Idea Implementation: The Innovation Hub will manage a standardized, efficient process to implement any post-R&D expanded pilot testing, help innovation owners publicize projects to internal and external stakeholders, and scale ideas throughout the organization.
- Archiving Best Practices: The Innovation Hub will track the overall Company innovation portfolio to help innovation reach all parts of the Company, building upon successes and learning from failures.

The Innovation Initiative program will require O&M funding to institute the elements described above for RY1 through RY3. The expenditures are to develop the projects and for additional employees, one new employee will be required in each Rate Year to support and implement the projects. The annual project expenditures were developed through benchmarking the annual innovation spend of over twenty utilities, and personnel increases are based on the number of potential innovation projects already identified, but not yet funded or supported, by the Company. In total, the Company estimates that the expenses for this initiative will be $2.256 million in RY1, $2.481 million in RY2 and $3.549 million in RY3, for a total of $8.286 million.

Justification:

Con Edison believes that both core and transformative innovation are important to deliver value to our customers and other stakeholders, with each type of innovation development deserving of appropriate resourcing. These transformative innovation activities have the highest level of potential impact, require coordination and change across multiple departments within the Company, and involve a significant degree of uncertainty regarding the potential outcome. Therefore, the Innovation Initiative creates a new structure for identifying, developing, and scaling these innovation activities that fall outside the areas addressed by our existing R&D and REV Demonstration activities. In addition, the Initiative will play a critical role in maximizing the Company's value from ongoing innovation activities as the Innovation Hub will establish a standard process to drive cross departmental coordination, communicate shared learnings across all areas of the business, and develop a rapid, rigorous, yet agile, process to start and stop the development of initiatives based on their progress.

In developing the Innovation Initiative model, Con Edison interviewed the key innovation leads of twenty-two utilities. Key learnings from this benchmarking included the need to staff innovation teams with full-time personnel who have the relevant skills to shepherd innovations through the various levels of testing, development and executive approvals found within the utility.

Supplemental Information:

- Alternatives: There exist a wide variety of alternatives to the model the Company proposes, but those alternatives can be categorized generally in two ways, 1) paying third parties to bring innovation to the utility or "outsourcing" innovation and 2) sequestering those who work on innovation in an "innovation center" or department intentionally separated from the rest of the utility.

In benchmarking with the other utility innovators, it was evident that innovation brought in directly by third-party innovation sources, even those associated closely with the utility industry, generally had the longest lead time to fully impact the organization and were of lower quality and strategic relevance. These innovations were usually borne from an idea generated outside the utility, at a lab or university, which was then adapted for utility use. Con Edison believes this type of innovation is best explored by our existing R&D organization, where the values of the utility can be incorporated into the innovation concept prior to wide-spread implementation throughout the organization.

Similarly, sequestering innovation to designated innovation centers within the organization not only detracts from the R&D role but limits the innovations coming from outside the innovation center. By removing innovation from the core business, it makes the task of collaborating with – and impacting – the core business much more difficult. Con Edison believes that creating a culture of innovation is so critical to our success that we need to build this transformative and cross-cutting innovation capability internally with the Innovation Hub acting as facilitating agents for the innovation owners.

Instead of more centralized or outsourced models which minimize the impact of innovation on the utility, we are designing a "distributed" innovation approach to generate ideas and solutions from the people closest to the problem. Owners of innovation initiatives come from across Company departments and ensure the organizational "muscle" or capability to innovate is built throughout the organization. We believe this approach will generate increasing benefits over time as the importance of innovating only grows.

- <u>Risk of No Action</u>: The pace of technology change and continued elevation of customer expectations means that – if Con Edison does not keep pace – the Company risks not executing on the objectives REV sets out for us. Con Edison believes the approach it has designed will increase the speed and effectiveness of innovation at the Company, facilitate the integration of new technology, improve our ability to work effectively with 3rd parties, all while laying the groundwork to build even greater advances over time.

- <u>Non-financial Benefits</u>:
  Due to the uncertain nature of innovation, not all projects will ultimately be successful nor address each of these non-financial benefits. However, successful projects will address one or more of the following benefits:

  1. **Improve safety -** Innovations originating within the operating organizations, supported by Innovation Common Fund backing, are given a better chance to be standardized and spread to all areas of the company by the Innovation Hub.
  2. **Culture** – Promotes openness to new ideas and business models and engages employees of all levels to innovate to improve the business and customer experience.
  3. **Increased transparency -** Customers and partners become aware of the Company's commitment to innovation, and its process to achieve innovative solutions to utility challenges.
  4. **Efficiency** – A standardized process for evaluating projects, clear project ownership, rigorous governance, and clear metrics will provide an indication of what success "looks like" and will minimize unproductive interactions internally and externally.
  5. **Improve customer experience:** Measured by our JD Power score or direct feedback on individual projects from customers and external stakeholders.

- <u>Summary of Financial Benefits (if applicable) and Costs</u>:
  Due to the uncertain nature of innovation, not all projects will ultimately be successful nor address

each of these financial benefits. However, successful projects will address one or more of the following benefits:

1. **Reduced O&M -** measured by operational expenditures
2. **Improve capital efficiency -** measured by capital spend per customer
3. **Increase non-traditional earnings -** measured by revenue

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable):
  - Research & Development **-** early stage and core, technology-only initiatives, as discussed above
  - REV-Demo Projects – projects that test new business models, as discussed above

- Basis for Estimate:

  The Company has designated two new funding streams which are necessary to deliver on our innovation capabilities:

  Corporate-wide innovation resource (O&M)
  Establish an **Innovation Common Fund**, held at the corporate level (President CECONY). Funding is for concept development, testing, prototyping, piloting, and seed funding for scaling discrete innovation projects. Estimates for the amount of funding required are based upon benchmarking with other similar utilities and the amount of projects identified, but not yet funded or supported, by the Company and the expected growth of innovation projects based upon this initial sampling.

  Corporate-wide innovation management (O&M)
  Activities of the **Innovation Hub** (labor, professional services, IT tools). The resource level will scale over time based on the personnel required to administer the number of potential innovation projects already identified, but not yet funded or supported, by the Company and expected growth of innovation projects based upon this initial sampling. The table below represents the incremental FTEs and estimated active annual transformative projects.

	2018	Projected 2019	Projected 2020	Projected 2021	Projected 2022	Projected 2023
Innovation Management: Total Incremental FTEs	**0**	**1**	**1**	**2**	**3**	**3**
Active transformative projects in pipeline	**5**	**6**	**7**	**7**	**10**	**10**

Annual Funding Levels ($000):

Historic Elements of Expense

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P					5	5
Other						
Total					**5**	**5**

Future Elements of Expense ($000):
The Company requests $8.286 million over the 2020-2022 rate period. The annual funding schedules are presented in the table below, including the expected funding in 2019 and 2023, for reference.

Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	$235	$300	$486	$734	$749
M&S	$367	$437	$446	$649	$662
A/P	$1,204	$1,415	$1,443	$2,057	$2,098
Other	$102	$104	$106	$108	$110
Overheads	$0	$0	$0	$0	$0
Total	**$1,908**	**$2,256**	**$2,481**	**$3,549**	**$3,620**

Exhibit ___ (CES-8) EAM Formulas and Target Sources

DER Utilization

Air-Source Heat Pumps
Cooling savings: [ASHP installs] * [0.422 MWh/install]
Plus beneficial electrification (heating): [ASHP Installs] * [0.734 MWh/install]
Forecast source: the Company's program data

Batteries
[Battery inverter discharge rating (MWh)] * [365 days/year] + [Daily battery inverter discharge rating (MWh)] * [365 days/year] / [80% round trip efficiency]
Forecast source: historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends.

Combined Heat and Power
[MW CHP] * [8,760 hours per year] * [75% annual capacity factor]
Forecast source: historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends.

Community Solar Photovoltaics
[MW Solar PV] * [8760 hours per year] * [15.5% annual capacity factor]
Forecast source: historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends.

Demand Response

1. The incremental MW above the previous year's enrolled MW for the Commercial System Relief Program and Distribution Load Relief Program (DLRP) is divided by the number of networks (84) to get incremental new MW by network.
2. Event hours called include the number of hours called multiplied by the number of networks for all program events including test events.
3. The MWh called is then multiplied by each program's yearly performance factor to arrive at final annualized MWh.

Forecast source: the Company's program data

Distributed Wind Energy
[MW Distributed Wind] * [8760 hours/year] * [15% annual capacity factor]
Forecast source: historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends.

Electric Buses
[Incremental electric buses] * [72.89 kWh/day] * [365 days/year]
Forecast source: data from the MTA and Westchester County

Fuel Cells
[MW Fuel Cells] * [8,760 hours/year] * [75% annual capacity factor]
Forecast source: historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends.

Light-Duty Electric Vehicles
Battery Electric Vehicles (BEVs): [Incremental registered BEVs] * [10.33 kWh/weekday] * [weekdays/year]
Forecast source: historical registration trends from the Department of Motor Vehicles

Plugin Hybrid Electric Vehicles (PHEVs): [Incremental registered PHEVs] * [7.0 kWh/weekday] * [weekdays/year]
Forecast source: historical registration trends from the Department of Motor Vehicles

Ground-Source Heat Pumps
Cooling savings: [GSHP installs] * [1.096 MWh/install]
Plus beneficial electrification (heating): [GSHP Installs] * [2.380 MWh/install]
Forecast source: the Company's program data

Ice Energy Storage
[Installs] * [0.55kW/ton] * [Tons/install] * [Hours/charge] * [Total annual charges]
Forecast source: the Company's program data and customer project data

Rooftop Solar Photovoltaics
[MW Solar PV] * [8760 hours/year] * [14.1% annual capacity factor]
Forecast source: historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends.

Electric Greenhouse Gas Emissions

Air-Source Heat Pumps
Emissions savings from cooling: [ASHP installs] * [0.422 MWh/install] * [Grid kg CO_2e/MWh]
Forecast source: the Company's program data

Batteries
[Battery inverter discharge rating (MWh)] * [Discharge MWh/day] * [365 days/year] * [Peak kg CO_2e/MWh] – [Charge MWh/day] * [365 days/year] * [Grid kg CO_2e/MWh] / [80% round trip efficiency]
Forecast source: historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends.

Community Solar Photovoltaics
[MW Solar PV] * [8760 hours/year] * [15.5% annual capacity factor] * [Grid kg CO_2e/MWh]
Forecast source: historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends.

Demand Response
[DR MWh] * [Peak kg CO_2e/MWh]
Forecast source: the Company's program data

Distributed Wind Energy
[MW Distributed Wind] * [8760 hours/year] * [15% annual capacity factor] * [Grid kg CO_2e/MWh]
Forecast source: historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends.

Electric Buses
[Incremental electric buses] * [Annual MWh/electric bus] * [Mile/MWh] * [[kg CO_2e/mile diesel bus] – [kg CO_2e/mile electric bus]]
Forecast source: data from the MTA and Westchester County

Light-Duty Electric Vehicles
Battery Electric Vehicles (BEVs): [Incremental BEVs] * [Annual MWh/BEV] * [Mile/MWh] * [[kg CO_2e/mile internal combustion engine vehicle] – [kg CO_2e/mile BEV]]
Forecast source: historical registration trends from the Department of Motor Vehicles

Plugin Hybrid Electric Vehicles (PHEVs): [Incremental PHEVs] * [Annual MWh/PHEV] * [Mile/MWh] * [[kg CO_2e/mile internal combustion engine vehicle] – [kg CO_2e/mile PHEV]]
Forecast source: historical registration trends from the Department of Motor Vehicles

Ground-Source Heat Pumps
Emissions savings from cooling: [GSHP installs] * [1.096 MWh/install] * [Grid kg CO_2e/MWh]
Forecast source: the Company's program data

Ice Energy Storage
[Installs] * [0.55kW/ton] * [Tons/install] * [[[Discharge MWh/day] * [110 cooling days/year] * [Peak kg CO_2e/MWh]] – [[Charge MWh/day] * [110 cooling days/year] *[Grid kg CO_2e/MWh] / [90% round trip efficiency]]]
Forecast source: the Company's program data and customer project data

Rooftop Solar Photovoltaics
[MW Solar PV] * [8760 hours per year] * [14.1% annual capacity factor] * [Grid kg CO_2e/MWh]
Forecast source: historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends.

Voluntary Renewable Energy Certificates
[Number of VRECs] * [1 MWh] * [Grid kg CO_2e/MWh]
Forecast source: Company program data and the New York Generation Attribute Tracking System.

Natural Gas Greenhouse Gas Emissions

Air-Source Heat Pumps
Emissions savings from heating (avoided natural gas): [ASHP installs] * [[Avoided Dth] * [kg CO_2e/Dth_{CH4}] – [MWh heating] * [Grid kg CO_2e/MWh]]
Forecast source: the Company's program data

Ground-Source Heat Pumps
Emissions savings from heating (avoided natural gas): [GSHP installs] * [[Avoided Dth] * [kg CO_2e/Dth_{CH4}] – [MWh heating] * [Grid kg CO_2e/MWh]]
Forecast source: the Company's program data

Heat Pump Water Heaters
[HPWH installs] * [[Avoided Dth] * [kg CO_2e/Dth_{CH4}] – [MWh heating] * [Grid kg CO_2e/MWh]]
Forecast source: the Company's program data

Exhibit ___ (CES-9) Summary of EAM Basis Points

Electric EAMs		2020	2021	2022
Electric Energy Efficiency (E3 EAM)	Min	7.0	7.0	7.0
	Mid	21.0	21.0	21.0
	Max	35.0	35.0	35.0
Electric Peak Reduction (EPR EAM)	Min	5.0	5.0	5.0
	Mid	15.0	15.0	15.0
	Max	25.0	25.0	25.0
DER Utilization (DER EAM)	Baseline	4.0	4.0	4.0
	Mid	12.0	12.0	12.0
	Max	20.0	20.0	20.0
Electric Greenhouse Gas Emissions Reduction (EGHG EAM)	Baseline	4.0	4.0	4.0
	Mid	12.0	12.0	12.0
	Max	20.0	20.0	20.0
TOTALS	Min	20.0	20.0	20.0
	Mid	60.0	60.0	60.0
	Max	100.0	100.0	100.0

Gas EAMs		2020	2021	2022
Natural Gas Energy Efficiency (GE2 EAM)	Min	7.0	7.0	7.0
	Mid	21.0	21.0	21.0
	Max	35.0	35.0	35.0
Natural Gas Peak Reduction (GPR EAM)	Min	4.0	4.0	4.0
	Mid	12.0	12.0	12.0
	Max	20.0	20.0	20.0
Natural Gas Greenhouse Gas Emissions Reduction (GGHG EAM)	Baseline	3.0	3.0	3.0
	Mid	9.0	9.0	9.0
	Max	15.0	15.0	15.0
TOTALS	Min	14.0	14.0	14.0
	Mid	42.0	42.0	42.0
	Max	70.0	70.0	70.0

Exhibit ___ (CES-9) Summary of EAM Targets

Electric Targets		2020	2021	2022
Electric Energy Efficiency (GWh)	Min	EE*0.75	EE*0.75	EE*0.75
	Mid	EE	EE	EE
	Max	EE*1.25	EE*1.25	EE*1.25
Electric Peak Reduction (MW)	Min	EP*0.75	EP*0.75	EP*0.75
	Mid	EP	EP	EP
	Max	EP*1.25	EP*1.25	EP*1.25
DER Utilization (Annualized MWh)	Baseline	D	TBD	TBD
	Mid	D*1.1	TBD	TBD
	Max	D*1.2	TBD	TBD
Electric Greenhouse Gas Emissions Reduction (Lifetime Metric Tons CO2e)	Baseline	EG	TBD	TBD
	Mid	EG*1.1	TBD	TBD
	Max	EG*1.2	TBD	TBD

Gas Targets		2020	2021	2022
Natural Gas Energy Efficiency (MMDth)	Min	G*0.75	G*0.75	G*0.75
	Mid	G	G	G
	Max	G*1.25	G*1.25	G*1.25
Natural Gas Peak Reduction (MMDth)	Min	GP*.075	TBD	TBD
	Mid	GP	TBD	TBD
	Max	GP*1.25	TBD	TBD
Natural Gas Greenhouse Gas Emissions Reduction (Lifetime Metric Tons CO2e)	Baseline	GG	TBD	TBD
	Mid	GG*1.1	TBD	TBD
	Max	GG*1.2	TBD	TBD

CONSOLIDATED EDISON COMPANY OF NEW YORK INC.
MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
NYC OMB EXPENDITURES 2014-2018

Source: Monthly Transaction Analysis

OMB CATEGORY	2014	2015	2016	2017	2018
Highway	$ 403.7	$ 418.3	$ 437.1	$ 495.3	$ 530.4
Highway Bridges	$ 182.8	$ 129.1	$ 282.8	$ 397.1	$ 337.3
Water Mains*	$ 183.9	$ 200.8	$ 214.0	$ 282.3	$ 355.4
Sewers	$ 278.3	$ 280.8	$ 306.4	$ 359.8	$ 375.7
Total	$ 1,048.7	$ 1,028.9	$ 1,240.3	$ 1,534.5	$ 1,598.7

Source: October 2018 Capital Commitment Plan

OMB CATEGORY	2019	2020	2021	2022
Highway	$ 458.5	$ 835.0	$ 976.6	$ 999.2
Highway Bridges	$ 91.3	$ 1,087.9	$ 1,696.7	$ 1,643.4
WM-1	$ 76.8	$ 254.1	$ 186.5	$ 226.9
WM-6	$ 5.0	$ -	$ -	$ 92.5
Sewers	$ 334.1	$ 630.7	$ 645.1	$ 667.8
Total	$ 965.8	$ 2,807.7	$ 3,504.9	$ 3,629.8

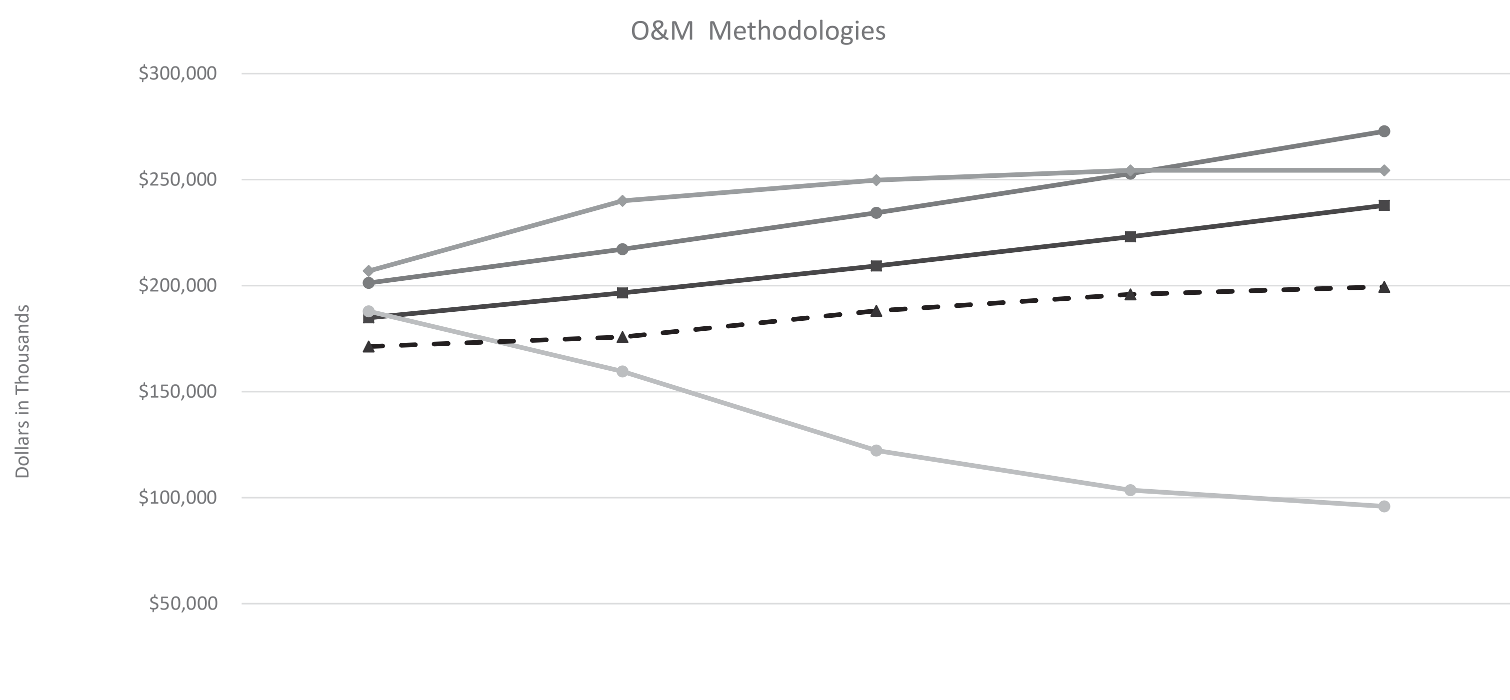
Notes

Years listed above are NYC fiscal years

Water Mains* = The totals from the M.T.A report are from WM-700 & WM-701 categories

Dollars in Millions

CONSOLIDATED EDISON COMPANY OF NEW YORK INC.
MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
O&M METHODOLOGIES

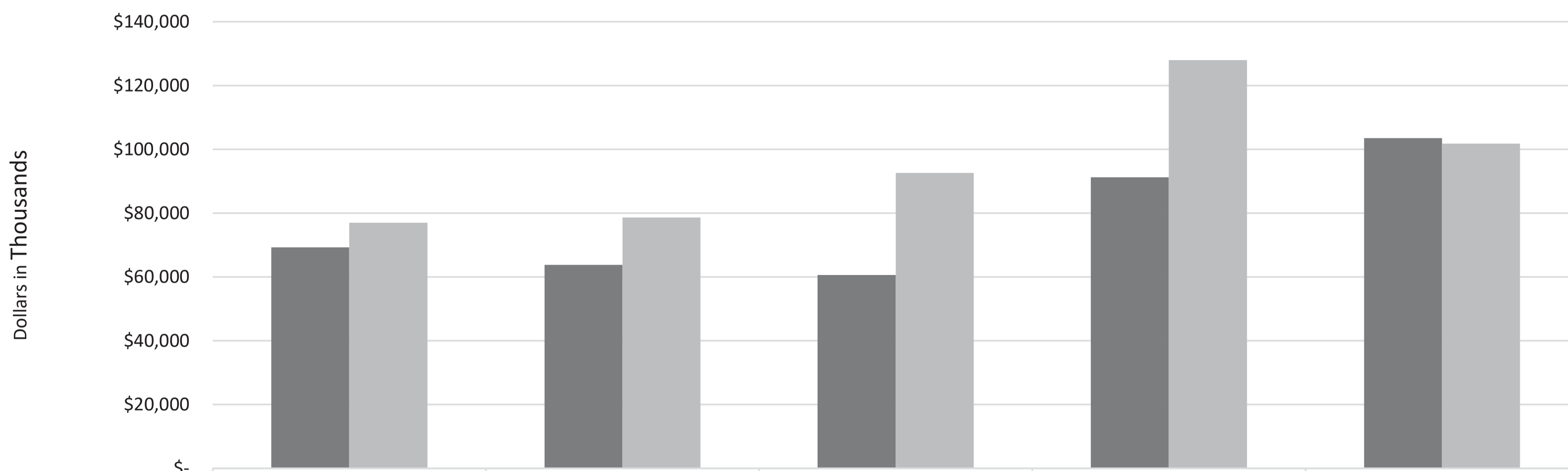


	2019	2020	2021	2022	2023
Exponential Growth	$201,257	$217,153	$234,303	$252,808	$272,775
Regression Analysis	$184,827	$196,609	$209,321	$223,037	$237,837
Project by Project	$187,937	$159,524	$122,214	$103,514	$95,903
NYC Calculation	$206,895	$239,956	$249,765	$254,403	$254,403
Forecast	$171,300	$175,778	$188,137	$195,851	$199,462

Notes
Dollars in Thousands and Rounded
Includes all Commodities and Company Labor

CONSOLIDATED EDISON COMPANY OF NEW YORK INC.
MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
FORECAST VERSUS CAPITAL EXPENDITURES

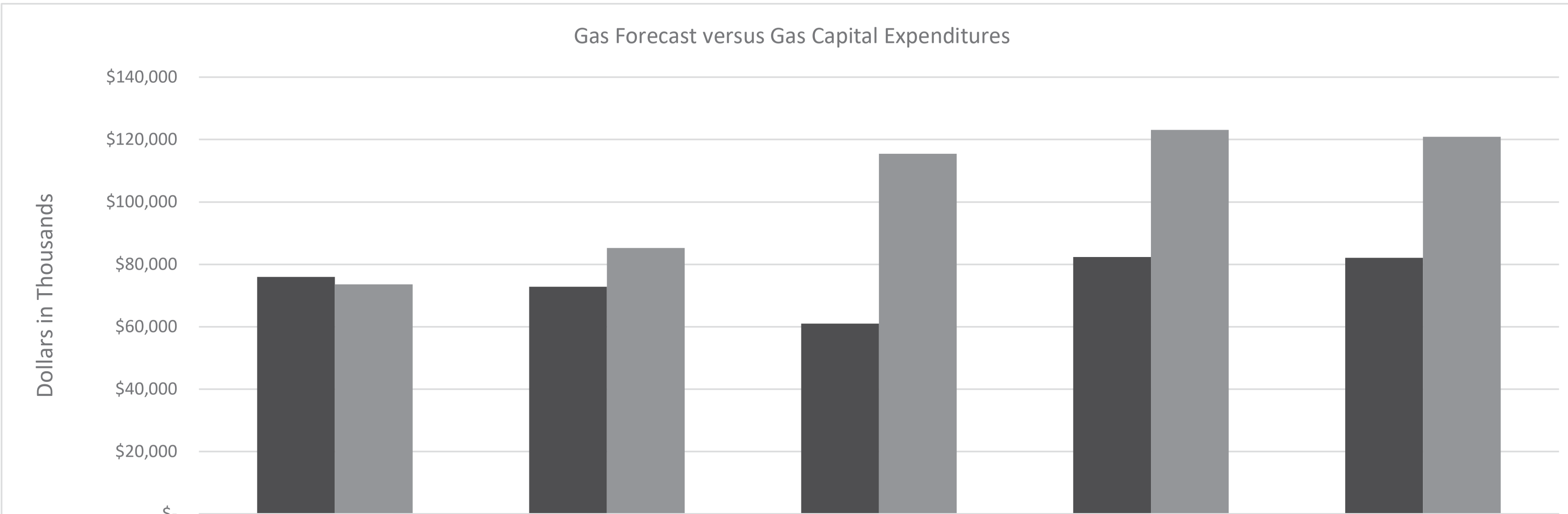
Electric Forecast Versus Electric Capital Expenditures



	2014	2015	2016	2017	2018
Electric Forecast	$69,302	$63,735	$60,561	$91,218	$103,527
Electric Expenditures	$76,953	$78,598	$92,606	$127,935	$101,828

Notes
Dollars in Thousands and Rounded

CONSOLIDATED EDISON COMPANY OF NEW YORK INC.
MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
FORECAST VERSUS CAPITAL EXPENDITURES



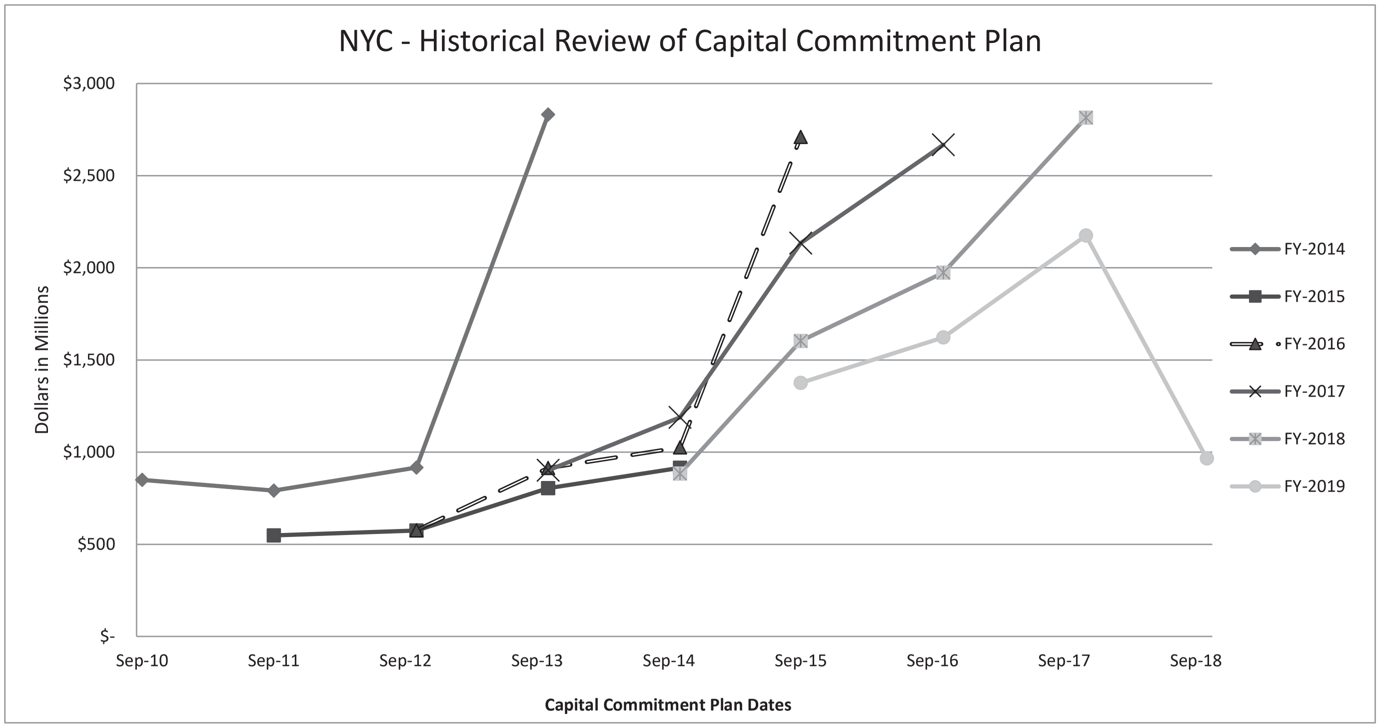
	2014	2015	2016	2017	2018
Gas Forecast	$76,000	$72,826	$60,985	$82,366	$82,055
Gas Expenditures	$73,598	$85,256	$115,421	$123,075	$120,902

Notes
Dollars in Thousands and Rounded

CONSOLIDATED EDISON COMPANY OF NEW YORK INC.
MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
NYC - HISTORICAL REVIEW OF CAPITAL COMMITMENT PLAN

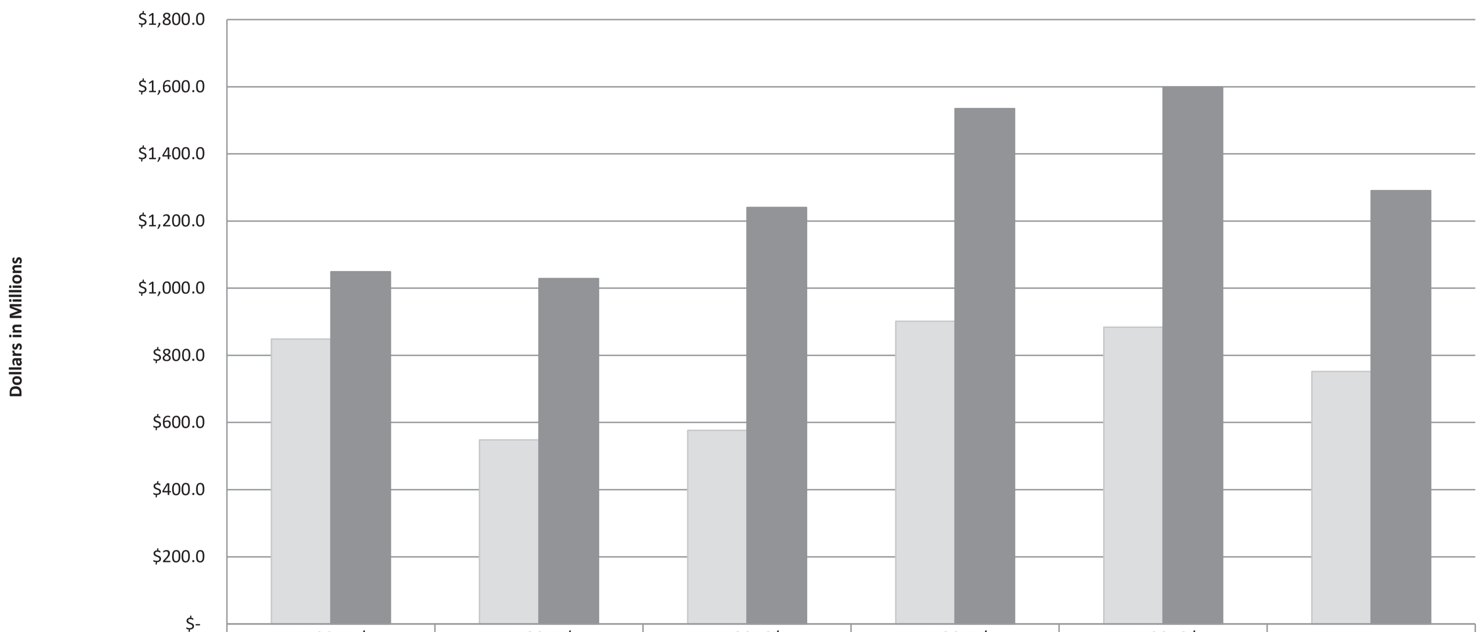
	Sep-10	Sep-11	Oct-12	Oct-13	Oct-14	Sep-15	Oct-16	Nov-17	Oct-18
FY-2014	$ 848.9	$ 791.5	$ 915.9	$ 2,831.3					
FY-2015		$ 548.3	$ 574.6	$ 804.4	$ 914.8				
FY-2016			$ 576.5	$ 914.0	$ 1,025.4	$ 2,709.6			
FY-2017				$ 901.4	$ 1,188.1	$ 2,134.3	$ 2,667.6		
FY-2018					$ 883.5	$ 1,602.4	$ 1,973.6	$ 2,815.1	
FY-2019						$ 1,375.8	$ 1,623.0	$ 2,174.9	$ 965.8

Note: Dollars in Millions and Rounded
FY 20XX = NYC fiscal years



CONSOLIDATED EDISON COMPANY OF NEW YORK INC.
MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
NYC INITIAL COMMITMENT VERSUS NYC ACTUAL EXPENDITURES

NYC Initial Commitment versus NYC Actual Expenditures

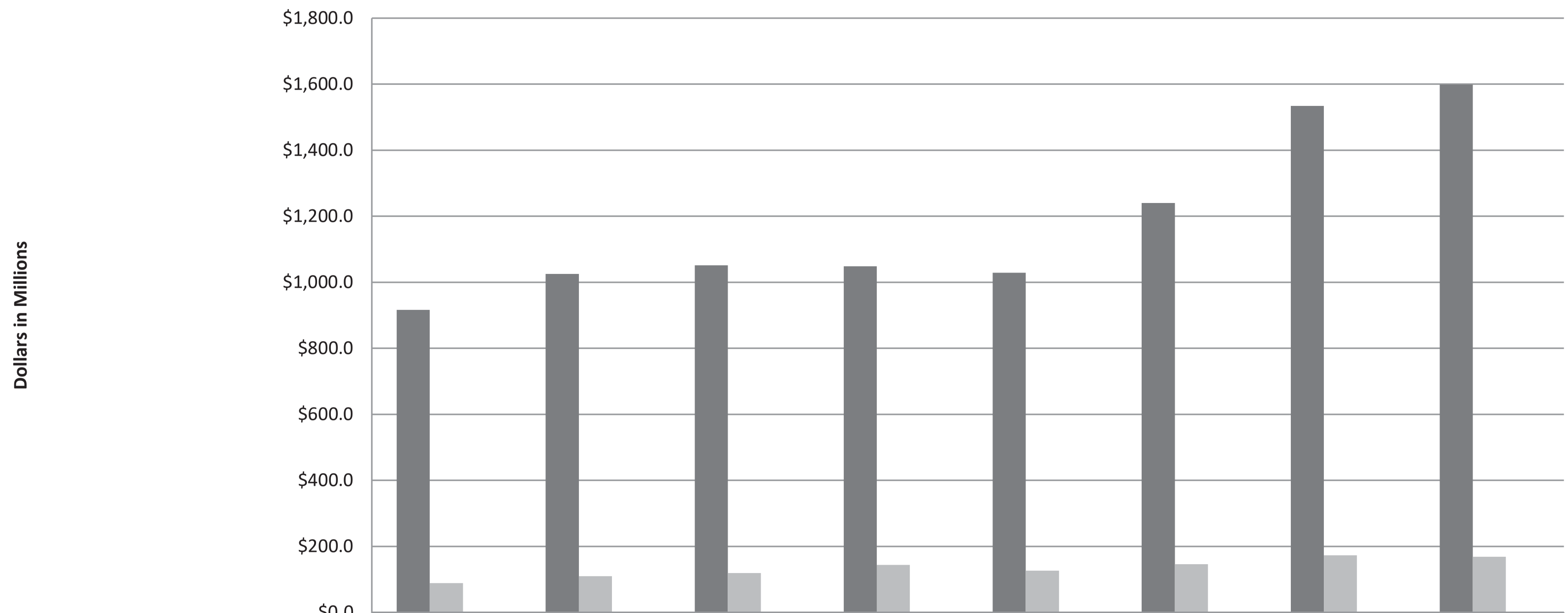


	FY2014 / Apr '10	FY2015/ May '11	FY2016/ May '12	FY2017/ May '13	FY2018/ May '14	Average
Initial Forecast	$848.9	$548.3	$576.4	$901.4	$883.5	$751.7
Actual Expenditures	$1,048.7	$1,028.9	$1,240.3	$1,534.5	$1,598.7	$1,290.2
% of Actual versus Initial	123.5%	187.7%	215.2%	170.2%	181.0%	171.6%

Notes:
Initial Forecasts are from the OMB Capital Commitment Plan
Actual Expenditures are from the OMB Monthly Transaction Analysis reporting
FY2014 / Apr '10 = City Fiscal Year / Publication Date
Dollars in Millions and Rounded

CONSOLIDATED EDISON COMPANY OF NEW YORK INC.
MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
NYC EXPENDITURES VERSUS CON EDISON EXPENDITURES

NYC Expenditures Versus Con Edison Expenditures



	2011	2012	2013	2014	2015	2016	2017	2018
NYC Expenditures	$916.5	$1,025.6	$1,051.7	$1,048.7	$1,028.9	$1,240.3	$1,534.5	$1,598.7
Company O&M	$89.1	$109.9	$119.4	$143.9	$126.6	$145.9	$172.7	$168.5
% of Company O&M to NYC Expenditure	9.7%	10.7%	11.4%	13.7%	12.3%	11.8%	11.3%	10.5%

Notes:
Company O&M includes all commodities including Company Labor
Dollars in Millions and Rounded

CONSOLIDATED EDISON COMPANY OF NEW YORK INC.
MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
ACTUAL AND FORECASTED O&M EXPENDITURES

O&M	2014	2015	2016	2017	Historical	2018	2019*	2020*	2021*	2022*	2023*
Electric	$ 99,949	$ 84,132	$ 92,339	$ 126,116	$128,655	$ 122,193	$ 126,213	$ 129,625	$ 140,026	$ 146,179	$ 148,577
Gas	$ 27,622	$ 28,560	$ 31,091	$ 26,872	$28,532	$ 27,229	$ 26,378	$ 27,055	$ 28,066	$ 28,940	$ 29,696
	$ 127,571	$ 112,692	$ 123,430	$ 152,988	$ 157,186	$ 149,422	$ 152,591	$ 156,680	$ 168,092	$ 175,120	$ 178,274

Notes
Dollars in Thousands and Rounded
All dollars exclude Company labor
Historical Year- 10/1/17-9/30/18
YYYY*- Forecast as of Q4 2018

CONSOLIDATED EDISON COMPANY OF NEW YORK INC.
MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
ACTUAL AND FORECASTED CAPITAL EXPENDITURES

Capital	2014	2015	2016	2017	2018	2019*	2020*	2021*	2022*	2023*
Electric	$ 76,953	$ 78,598	$ 92,606	$ 127,935	$ 101,828	$ 131,000	$ 193,000	$ 201,000	$ 210,000	$ 225,000
Gas	$ 73,598	$ 85,256	$ 115,421	$ 123,075	$ 120,902	$ 126,000	$ 101,329	$ 109,344	$ 116,757	$ 127,005
	$ 150,551	$ 163,854	$ 208,027	$ 251,010	$ 222,730	$ 257,000	$ 294,329	$ 310,344	$ 326,757	$ 352,005

Notes
Dollars in Thousands and Rounded
YYYY*- Forecast as of Q4 2018

X	Capital
	O&M

2019 – Customer Operations

Project/Program Title	Data and Analytics
Project Manager	Rebecca Lessem
Hyperion Project Number	PR.22678024
Status of Project	In progress
Estimated Start Date	January 1, 2018
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

The Data and Analytics program is a key enabler to improving the customer experience and reducing operating costs by gaining a deeper understanding of customer needs through robust business intelligence. The Company has previously had success understanding customer needs by conducting direct customer research such as surveys, focus groups and interaction with the Company's online Con Edison Advisory Community. However, to meet rising customer expectations, best-in-class companies across industries are now utilizing advanced data analytical tools in addition to traditional customer research to more deeply understand customer needs and improve service.

The Company has a significant amount of data about its customers, including but not limited to data on energy consumption, payment history, field visits, rate/program enrollment (e.g., energy efficiency programs, time of use ("TOU") rates, level payment plan, low income discounts, etc.), and the type and channel of historical interactions with the Company (including detailed interactive voice response ("IVR"), chat and web logs). This valuable data currently resides in numerous internal systems and databases. Through the Data and Analytics program, Con Edison will utilize modern data and analytics platforms to connect these data sources, and sort through the resulting data to identify patterns, trends, correlations and relationships. This connected data can then be utilized to develop a better understanding of customer pain points and predict current and future customer needs. Examples of the types of actionable insights that the Company seeks to develop through the Data and Analytics program include, but are not limited to, the following:

- Customer segmentation on attributes such as behavior, sentiment, communications preferences, and energy needs, in order to more effectively target customers for programs and services that will meet their needs.
- Propensity to adopt certain programs (e.g., eBill, auto-pay, payment assistance, time-variant rates) to achieve more timely and effective customer target marketing, program adoption and customer service.
- Next Best Action ("NBA") recommendations that can be offered to customers via self-service tools and Company employees. NBA is a customer-centric model that evaluates a customer's past behavior, recent actions, interests, and needs to identify the most effective action to achieve desired outcomes. It considers the different actions that can be

taken by a specific customer and decides the 'best' one. Examples include utilizing NBA models to prompt a Customer Service Representative ("CSR") to make a specific program, service offering, or account resolution recommendations and presenting these same options to a given customer on the web.

- Cross-channel analytics (e.g., web, IVR, chat, email, phone, text, mobile apps) to better understand a customer's path and intents, to allow for quicker service by an agent, or to conduct a root cause analysis of customer pain points during a self-service process. For example, cross-channel analytics would be used to determine where in a given web transaction customers are experiencing a problem that in turn results in a CSR-based phone call. Such insights can be used by a CSR to understand that a customer was on the web, what they were trying to complete, and allow the CSR to more quickly and effectively resolve the issue. In addition, this insight can be utilized to identify an issue with the web transaction, which resulted in the customer needing to call instead of completing the transaction in a self-service channel.
- Operational analytics to measure process efficiency and compliance, and identify areas for improvement or the need for new solutions. For example, deep call analytics can provide insight into which types of calls are resulting in back office cases, and what the average resolution time is for such cases.
- Speech / natural language analytics to understand purpose of a customer's call / chat, sentiment, resolution, and satisfaction. For example, mining chat data with analytics to more deeply understand chat trends, CSR performance (for live chat interactions), and overall customer satisfaction.
- Quality assurance / fraud reviews, to facilitate detection of employee or customer fraud. For example, data analytics can be used to identify accounts or employees who exhibit unusual types of transactions over time such as repetitive refunds, transfers, or improper supervisory approval. The Company has already begun work in this area, launching a pilot project in 2018 to use data profiling and advanced analytics to identify outliers or anomalous behavior. As part of this effort, the Company created an initial set of analytics algorithms and dashboards, including executive level dashboards for the use case of detecting internal fraud through inappropriate escalations of approvals.

To develop this program the Company conducted a study to define business requirements and a technical design and architecture. The scope of the study included the following activities:

- Documentation of a detailed list of high value insights that could be gained through advanced data analytics,
- Detailed assessment of the applications that store customer data,
- Development of a comprehensive roadmap detailing the plan to move customer data from dispersed applications to an analytics data platform(s), including the approach for necessary system integration, and
- Define a recommended operating model, including governance and proper management of data platform and analytic tools.

A preliminary detailed list of high priority customer analytics targeted use cases is included as Attachment 1.

The Company plans to undertake the following workstreams as part of the Data and Analytics program:

- Implement the target architecture design, using a phased approach to migrating data which will allow iterative results and associated valuable insights from the start.
- Integrate identified data sources with the target data platform, focusing on data sources required to enable the highest priority analytic use cases as listed in Attachment 1.
- Develop data models and algorithms to accomplish key analytic use cases.
- Develop dashboards and reports to allow operational employees to achieve greater business intelligence through advanced data analytics.
- Connect key predictive data models and algorithms to internal and external facing systems (e.g., CSR desktop (phone), web, chat, IVR, email, text, mobile apps- to drive more personalized service.
- Update and extend data models by periodically refining algorithms and cleansing data.

Capital funding requested for this program will cover costs to incorporate data into the platforms selected, develop models that integrate with the Company's self-service systems and test them, and create executive-level dashboards.

As described in the Customer Operations Panel testimony and the Justification Summary below, the Data and Analytics program will contribute to achievement of Customer Operations' Business Cost Optimization ("BCO") Savings targets. All of the operations and maintenance ("O&M") costs associated with this program are being treated as costs to achieve BCO savings, and have therefore been netted out of Customer Operations' total BCO savings target. As such this white paper does not include any O&M requests or corresponding program changes for this program.

Justification Summary:

In addition to driving the specific benefits described below, the business intelligence that will be unlocked by the Company's Data and Analytics program is a foundational and essential enabler for the entire Next Generation Customer Experience initiative proposed by the Customer Operations Panel, including the Journey Mapping, Digital Customer Experience, Back Office Automation, and Bill Redesign programs.

Driving an improved customer experience through business intelligence is also essential to meeting rising customer expectations. Con Edison faces a dynamic market of evolving customer expectations, expanding channels of interaction, emerging products and services, and an evolving role as an energy provider. Customers now expect proactive digital communication and prompt, competent service at any hour of the day or night. Additionally, new customer opportunities are emerging with the increasing adoption of smart technology, distributed generation, mobile devices, and the integration of internet-enabled platforms and devices such as social media and advanced thermostats. After taking into consideration the Company's implementation of smart meters, increasingly sophisticated rate designs and clean energy programs, it is clear that customer needs and expectations will continue to press beyond traditional utility customer experiences toward more personalized interactions and informed energy choices. To meet these rising expectations while also harnessing customer interest in clean energy solutions, the Company must develop and deliver customer-focused solutions that create personalized and simple experiences, which in turn drive operational excellence through improved efficiency and reduced costs.

According to Gartner, a leading information technology research and advisory company, "customer analytics is considered the most critical technology investment for [customer experience] improvement projects, with half of all organizations intending to increase investment during 2018 in areas such as customer journey, customer needs analysis and digital marketing analytics."[1] Con Edison will utilize analytic tools in a number of ways to improve the customer experience as described in this white paper. These tools will allow us to develop a deep understanding of the specific preferences of our customers, such as their desired frequency of billing reminders and optimal payment plans (i.e., plans that they are likely to keep current and not break). The Company will also utilize customer interaction insights from advanced analytics to provide customer contact employees and customers (through self-service channels) with personalized real-time customer specific assistance. Finally, advanced data analytics will be utilized to create dashboards that provide CSRs a more complete view of the customer, saving both customers and employees time and potential frustration when resolving a customer issue. CSRs will have insight into what the customer is interested in based on their previous interactions and be able to make the right suggestion to the customer the first time, avoiding an extended phone call.

These business intelligence-enabled improvements in customer experience are also a key driver of the Company's efforts to streamline processes and reduce costs, and are required to achieve the BCO savings described in the Customer Operations Panel testimony. BCO savings stemming from the Data and Analytics program include costs associated with deflection of CSR-answered calls, reduction in the length of calls due to better information, and reduced termination and uncollectable bills.

Finally, the Company plans to utilize data and analytics to review millions of transactions to detect potential employee or customer fraud. The Company processes millions of customer transactions each year, including payments, refunds, billing adjustments, balance transfers and credit actions. The use of advanced analytics is necessary to review this vast data to identify patterns and outlier behaviors which should be reviewed for potential fraud. Without the proper data analytics, dashboards, and advanced data models, the Company risks failing to detect potential employee or customer fraud.

In summary, without a properly funded and effectively managed Data and Analytics program, the Company cannot deliver the improved customer experience, fraud detection, and BCO savings described in this white paper, nor can it deliver the benefits associated with the rest of the Next Generation Customer Experience programs.

Supplemental Information:

- Alternatives: The alternative to investing in the Data and Analytics program is to continue to build customer experience solutions without the deeper intelligence and insights about customer interactions, needs and preferences. Lack of effective insights from the vast customer data the Company has on its customers will result in less effective

[1] Gartner, Customer Experience 2018 Benchmarks: Turning Return on Investment Into Reality, Nick Ingelbrecht, Ed Thompson, Olive Huang, Melissa Davis, Julie Meyer, May 2018 https://www.gartner.com/document/3873985

customer solutions. Without effective customer experience solutions, the Company will fail to meet customers rising expectations, and leverage the opportunities to reduce costs as described. In fact, over time as expectations rise, cost associated with customer service would likely increase due to frustrated customers requiring increase interactions with the Company.

- Risk of No Action: The risk of no action is the same as the risk described in the Alternatives section above.

- Non-Financial Benefits: As described in detail above, the Data and Analytics program is foundational to the Company's efforts to improve the customer experience associated with all of the entire Next Generation Customer Experience initiative. With deep customer insights, the Company can meet rising customer expectations and engage them with new programs and services that will advance progress toward New York State's clean energy goals.

- Summary of Financial Benefits (if applicable) and Costs: The Data and Analytics program will result in BCO savings as described in details in the Customer Operations Panel testimony.

- Technical Evaluation/Analysis: The Company has worked to deeply understand the value of customer data and analytics, and develop its plans and approach to the Data and Analytics program. Additionally, the Company has studied the specific use case of fraud detection analytics with the help of leading consultants in this area and, as noted above, launched a pilot project in 2018 to use data profiling and advanced analytics to identify outliers or anomalous behavior.

- Project Relationships (if applicable): As noted, the Data and Analytics program is foundational and essential to the success of the entire Next Generation Customer Experience initiative. In addition, customer engagement with smart meters, clean energy programs and time-variant rates can be improved through deep customer analytics. Finally, the Company has developed an approach and architecture for customer data analytics which considers the pending migration to a new Customer Information System (see Customer Energy Solutions Panel testimony). The Company plans to develop analytics models using technology which can be re-integrated with the new CIS source data without significant stranded costs. Finally, the Data and Analytics program is working in partnership and coordination with the Company-wide efforts around analytics as described in the Information Technology Panel testimony on the Data Analytics Center of Excellence.

- Basis for Estimate: As noted, the Company's estimates were based on studies with consulting firms that have deep understanding of customer and fraud-related analytics.

Total Funding Level ($000):

Capital - Historical Elements of Expense

(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P						$1,014
Other						
Total						**$1,014**

Capital - Request by Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor					
M&S					
A/P	$2,775	$5,000	$5,000	$5,000	$5,000
Other					
Overheads					
Total	**$2,775**	**$5,000**	**$5,000**	**$5,000**	**$5,000**

Data and Analytics Use Cases

Use Case	Use Case Description	Benefits
Customer Analytic Record (CAR)	The CAR concept embodies the datasets required to develop customer models and analysis. It is a customer-centric view (neither account nor premise centric) and includes multitudes of variables providing a unified view of all customer interactions, profiles, interaction, service usage and other attributes, and pinpoints those that will be useful in a particular situation. The CAR serves as the framework for analytic processes	Increase Customer Satisfaction (CSAT)
Customer Segmentation	Classify customers based on perception and behaviors into groups that perceive and respond to specific offerings in a similar way	Reduced O&M, Increased CSAT
Self Service (MyAccount) Propensity	Propensity to adopt self-service. Predictive model to evaluate those attributes of customers who self-serve and score the remaining customer base on those attributes. The Self-Service propensity score is then leveraged in self-service awareness campaigns to drive an increase in Self-Service usage with those customers most likely to adopt.	Increase Customer Satisfaction
Web-to-Call Linking	Analyzing the trends of customers bouncing from the web and calling in to address their problems. Involves root cause analysis.	Reduced O&M, Increased CSAT
IVR Drop Out Analysis	Analyzes: What percentage of callers opted out of the IVR call flow (by hitting zero to speak to an agent)? At which prompt did the largest percentage of callers do so? Can the prompt or call flow be rewritten to decrease opt-outs?	Reduced O&M, Increased CSAT
Repeat Caller Analysis	Repeat caller analysis within the contact center to determine key drivers of repeat calls.	Reduced O&M, Increased CSAT
Call Volume Drivers - Root Cause Analysis	Root cause analytics into call volume drivers	Reduced O&M, Increased CSAT
Escalated Call Analytics	Escalated caller analysis within the contact center to determine key drivers of escalated calls and executive cases.	Reduced O&M, Increased CSAT
Measuring the Effectiveness of the Improvements to the Digital Experience	Connecting digital experience with call in numbers. Knowing if someone is online real-time and if they are running into problem. Tracking call history linked to that problem / subject.	Reduced O&M, Increased CSAT
Machine learning driven IVR routing	reason for call logic/routing dynamic update, caller ID match rate, correct agent, opt out rate analysis, misroute analysis	Reduced O&M, Increased CSAT
CSR Performance / Productivity	Real-time dashboard with KPIs by agent, workgroup (AHT, escalation, repeat, # calls, talkover %, silent %., call routing accuracy)	Reduced O&M, Increased CSAT
Workforce Performance Monitoring	Quality & Performance dashboard and reports to monitor contact center agent performance	Reduce O&M (Cost savings)

X	Capital
X	O&M

2019 – Customer Operations

Project/Program Title	Digital Customer Experience (“DCX”)
Project Manager	Eric Mastroianni
Hyperion Project Number	PR.21088410
Status of Project	In progress
Estimated Start Date	January 2015
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

The DCX program is a multi-year program that will continue to refine and build upon the digital platform developed during the current rate plan. The Company has already improved the online customer experience byredesignin the www.conedison.com and www.coned.com external websites and introduced a new mobile-enabled design, My Account portal, and mobile apps (“IOS” and “Android”).

DCX will continue to be guided by these principles during Rate Years 1-3:

- **Customer First –** Through surveys, in-depth interviews and journey mapping, customers are guiding the Company to a best-in-class digital customer experience.
- **Simplicity –** Customers have indicated through usability testing and benchmarking that they expect simple and intuitive experiences when interacting with their utility.
- **Personalization –** Utilizing data-enabled analytics and customer-driven optionality to provide customers with relevant content and tailored solutions.
- **One Company –** DCX enables a collective, cross-functional approach and delivers a digital experience that is consistent across the entire website/app.
- **Agility –** An Agile operating approach underlays the solution architecture and positions Con Edison to quickly adapt to changes in customer preferences, markets and regulatory requirements.
- **Security –** Safeguarding customer information while maximizing usability is a central objective of DCX.

The DCX program will continue to use a customer centric, “Agile” project management approach (*i.e.*, an iterative and incremental method of managing the design and build of the digital platform) that will adapt project scopes to changing priorities based on customer feedback and analytics. The Company will engage customers in the development and design of strategic new offerings through various types of usability testing, including prototyping. In light of this flexible Agile project management approach, the Company will continue to update Department of Public Service Staff and stakeholders on the evolution of the DCX program through quarterly reports.

Key focus areas of the efforts to optimize and expand Con Edison's digital platforms during Rate Years 1-3 include the following:

- **Ongoing Optimization:** Embedded in the DCX work process is an ongoing review of customer feedback through the use of the "provide feedback" link throughout the web and mobile experience, post chat and transactional surveys, and focus groups. In addition, website analytics are continually reviewed to develop actionable insights. This information will the help Company identify opportunities to benefit customers and remove transactional friction points. Examples include changes to the placement of text, buttons and icons to make it easier for customers to find information and links, and streamlining of transactions flows (i.e. start service or report outage) to remove known pain points, or to optimize business rules to allow for improved service.
- **Transactional Expansion:** DCX will expand online self-servce offerings to include transactions that are only available through a Customer Service Representative ("CSR") today as well as new content to deliver additional value to specific customer segments. Examples include appointment scheduling and service reconnects, and expansion of commercial customer offerings such as improved data visualization and multi-account portfolio management.
- **Foreign Language Expansion:** The Company plans to expand its digital content to be fully translated in multiple languages, opening content and self-service offerings to additional foreign language customer segments, such as customers who speak Cantonese, Mandarin, Korean, Russian and Polish.
- **Data Sharing:** The Company seeks to expand business-to-business data sharing capabilities through the expansion of Green Button Connect ("GBC") data sets and opening secure application programming interfaces ("API") for additional data exchange opportunities with interested customers and third parties.
- **Technology Upgrades:** To meet customers' expectations, the digital platform must maintain a high level of reliability, and an error-free experience. To accomplish this, the Company will make upgrades to the Web Experience Management ("WEM") platform. Upgrades to the WEM platform will unlock new features and capabilities of our Sitecore Content Management System that have not been utilized to date, such as recent improvements to Sitecore Analytics Platform that will enable greater personalization opportunities. DCX will evaluate future upgrade features and capabilities to plan for timely upgrades so that, as technology evolves, Con Edison sites have the capability to keep up with industry changes and customer expectations. Additionally, DCX will also invest in the development of WEM functionality for content authors to allow for easier distribution of content across all digital channels and media, providing improved consistency across the digital experience.
- **Migrating remaining ancillary legacy web applications:** The DCX program will continue to migrate remaining legacy web applications to its WEM platform, including legacy portals used for Steam customers, data from legacy (i.e., non-Adanced Metering Infrastructure

("AMI")) interval meters, summary billing customers, streetlighting customers, and energy efficiency micro-sites where appropriate. Currently, each of these sites have differing log-in and design experiences with content and structures that are not aligned to the guiding principles of the DCX program. The Company will carefully evaluate and prioritize moving each of these legacy portals to the DCX experience, which will improve ease of use for customers accessing better content and account information under a single, updated DCX login.

- **Mobile App Services:** Enhancements will also be made to the mobile app functionality, including development of key features as they are expanded across the digital platforms, as noted above (e.g., implementation of new transactional offerings, content optimization, etc.). The Company also plans to explore and leverage mobile specific services such as use of a Global Position System ("GPS") to report an outage, push notifications for alerts, and use of mobile cameras to submit outage/safety (e.g., wires down) related issues. The initial mobile applications have been well received by customers with an average score of 4.6 out of 5 in the Android and IOS app stores. Additionally, the adoption and utilization of the Company's app continues to show positive trends. As customers adopt this technology, they will expect to see features and capabilities evolve as seen on other popular applications, for example, utilization of native phone technology for voice enabled transactions through Siri or Google Assistant so that customers can report an outage by simply saying "Siri, my power is out."
- **Personalization and Control:** Customers value control and personalized experiences. The DCX program seeks to create meaningful experiences that provide customers customized and tailored messaging and offerings based on an understanding of their needs. For example, a residential apartment dweller visiting the Company's website may see tailored messaging about energy efficiency programs for renters, or be offered payment plans or payment assistance options to customers in arrears when logging into My Account (i.e., after logging in the customer is presented with content 'tiles' that are likely more meaningful to their specific needs). To expand customer control, the Company will look to enhance its Preference Management Center to include additional notification types such as usage alerts and appointment notifications. The Company also plans to explore offering large commercial customers the ability to assign different access roles for different types of My Account users, providing more restricted access options and controls according to the user's role (e.g., Bookeeper; Building Manager).
- **Interactive Voice Enhancements:** The Company will also expand the DCX program scope to incorporate and optimize additional digital channels, such as Interactive Voice Response ("IVR"), text, and email management, including improvement of conisistency between these channels in key areas such as setting preferences for notifications. Additionally, the Company plans to explore natural language IVR expansion that uses a particular type of automated speech recognition ("ASR") technology that allows callers to say what they are calling about in a wide variety of ways, so instead of prompting them to say specific phrases, the system will typically just say something like: '*Welcome to Con Edison, how can I help you today?*' This technology will improve customer friction points on the existing IVR and allow for greater self-service containment (i.e., allow customers to complete all of their transactions on self-service channels, without needing to speak with a CSR).
- **Payment Enhancements:** The Company will expand customer payment options to integrate with third party pay partnerships (e.g., PayPal, Venmo, Apple Pay, and Google Wallet) that

will allow customers to pay Con Edison bills on their preferred payment platform. The Company also plans to create a wallet feature on the DCX platform so that customers can store multiple payment options with the Company. Others areas for further expansion of payment options include pay by text / SMS and options to split your bill between roomates.

- **Leveraging emerging technology:** The Company will continue to monitor both customer and evolving industry trends that will shape customer expectations to offer simple and convenient ways to transact across its digital platforms. This includes leveraging smart home technologies such as Amazon Alexa and Google Home to transact (i.e., "Alexa what is my Con Edison Bill?"). Other areas that DCX will consider include the utilization of new user experience approaches that are still in their infancy now but appear likely to mature quickly during Rate Years 1-3. DCX will also continue to support and build new and expanded features to support REV, AMI, and other programs such as smart home, electric vehicles and solar inititives to improve customer ability to control and monitor their energy usage.

Capital costs required to support the DCX program include labor and accounts payable costs associated with implementation of the capital work described above. These costs cover internal labor, vendor costs, and software and hardware costs, as needed. To continue the progress of the program, the Company proposes to continue with a digital focused team to expand the DCX platform based on the focus areas noted in this white paper.

The Company is also proposing O&M program changes for the DCX program in all three Rate Years. In the first Rate Year, the Company plans to reduce its DCX O&M spending to reflect the removal of vendor contract costs that were in the historic test year ("Historic Year") expenditures. In Rate Years 2 and 3, the Company is proposing small increases in funding following the Rate Year 1 reduction. The RY2 and RY3 upward adjustments are necessary for two reasons.

First, the Company must maintain the foundational information technology ("IT") infrastructure that was implemented in 2017-2019, which involves non-labor expenses such as software-related fees charged by vendor support and ongoing costs for technology solutions deployed by the DCX program. DCX technology fees fall into the following categories:

- **Software as a Service fees:** Identity Access Management, Preference Management, Feedback/Survey Tools, Ad-hoc Customer Engagement Platform enhancements; Notification Fulfillment
- **Cloud Hosting fees:** Azure cloud hosting environment to store DCX program code
- **Maintenance fees:** Web Experience Management Platform
- **Contractor Services:** Ancillary support functions filled by contactors to support ongoing maintenance and support of the DCX experience

Second, the Company requires funding for additional full time equivalent ("FTE") resources (*i.e.*, above the FTE utilized in the Historic Year) that are needed to provide day-to-day maintenance of the Company's digital architecture, manage the customer experience, and create and introduce new creative content.

As described in the Customer Operations Panel testimony and the Justification Summary below, the DCX program will contribute to achievement of Customer Operations' Business Cost Optimization ("BCO") Savings targets. Fifty percent of the operations and maintenance ("O&M") costs associated with this program are being treated as costs to achieve Customer Operations' BCO savings targets.

As such, the O&M costs shown below and the Customer Operations program change forms have been adjusted to reflect this treatment.

Justification Summary:

The DCX program has already delivered improved customer satisfaction, customer engagement, and reduced costs through call deflection. Since the launch of the new My Account experience in July 2017, the Company has seen monthly average users (i.e., the number of users who log in at least once in a month) dramatically increase from 99,000 to 376,000, suggesting increased customer engagement. These numbers also indicate that the transition of customers to the new experience has surpassed the Company's legacy experience, which had approximately 552,000 log-ins in the past 30 days prior to launch.

The Company's Net Promoter Score ("NPS" – a common metric for websites that is also referred to as an online user's 'likelihood to return') has increased from – 28.6 to +26.7. The average NPS score overall for utility websites is listed by Esource as – 3. However, customers' expectations of digital customer service are expected to increase based on their interactions with companies outside of the energy industry. In order to sustain this performance while also keeping up with rapidly changing customer expectations and evolving technology trends the Company must continue to invest in and modify DCX.

In addition, the Company's proposal to continue investment in the DCX platform is in line with the Company's approach to replacing its Customer Service System ("CSS") as described in the New Customer Service System Implementation Testimony in the Customer Energy Solutions Panel. The Company's customer facing experiences were designed to be viable as the Company migrates to the new CSS.. The Company will need to integrate the new CSS with the existing DCX platform as part of the transition. Cost associated with integrating the DCX platform to the new CSS have been included in the funding estimates for the new CSS program detailed in the Customer Energy Solutions Panel testimony.

Finally, the DCX Program is a key enabler of the Company's BCO goal of reducing operating costs. The Company has already seen positive trends in online/digital transactional activity that appear to support the conclusion that increased customer engagement on digital platforms is, in fact, deflecting calls. An example of this is the positive performance of the recently-released Start/Stop/Transfer functionality, which has enabled 228,000 completed transactions online since its launch in July 2017. The Company expects that continued investment in a robust digital platform that meets rising customer expectations will allow for increased adoption of self-service channels, which can avoid calls that need to be answered by a CSR. The DCX investments proposed in this white paper are essential to achieving the call deflection cost savings outlined in the Customer Operations Panel's BCO testimony. Without the proposed investments in its DCX program, the Company will not be able to achieve its call deflection forecasts and realize the associated operating cost savings.

<u>Supplemental Information</u>:

- <u>Alternatives</u>: Now that the DCX program is well underway, the only alternative to the investments proposed here would be to suspend capital investment in the DCX platform and instead perform maintenance work only on the Company's digital platform. The Company would not provide customers with a continuously improving experience that stays in step with their evolving expectations, which in turn would make customers less likely to utilize digital self-service options or engage in REV programs designed to provide energy management options such as new rates and programs that require sophisticated digital interactions. As noted, this will also reduce the ability for the Company to meet BCO related reductions in operating costs.

- <u>Risk of No Action</u>: There are several key risks associated with no action:
  - Diminished smartphone and tablet user experience due to lack of long term optimization planning and execution;
  - Declining customer satisfaction as users become increasingly frustrated with an aged experience and technology;
  - More customers contacting the Company's Customer Experience Centers rather than using self-service applications;
  - Inability to adapt to evolving customer and regulatory requirements;
  - Failure to support and leverage new customer engagement opportunities and emerging clean energy initiatives made possible by smart meter technology; and
  - Failure to reduce operating costs.

- <u>Non-financial Benefits</u>: The DCX program will result in a number of non-financial benefits, including but not limited to the following:
  - Improved customer satisfaction, through a comprehensive, simple and intuitive web experience;
  - Improved community relationships, through a more engaging and informative website;
  - Improved customer engagement, through proactive communications, additional choice, control and customer tools;
  - Improved accessibility for special needs customers, through content that meets regulations for hearing and visually impaired customers;
  - Improved agility, with a more robust technology suite, which allows for flexibility and iterative development of new content to better meet customer needs, outage communications, and regulatory initiatives; and
  - Improved resiliency related to storm, public safety, and other vital communications.

- <u>Summary of Financial Benefits (if applicable) and Costs</u>: O&M costs associated with this program are described above. O&M savings stemming from this program are described in the BCO section of the Customer Operations Panel testimony.

- Technical Evaluation/Analysis: A comprehensive technical evaluation of the DCX program was completed during the 2015 Phase 0 analysis. This analysis was utilized as the basis for scope, staffing, and cost estimates for the program. In addition, customer research was conducted to inform the evaluation. The research performed confirmed customer expectations regarding robust digital channels, and a simple engaging experience. Please refer to the Company's 2016 rate filing in Case 16-E-0060 for further information.

  It addition, the Company has continued to evaluate investments required to meet customer expectations in future years. This evaluation included a review of future customer needs and trends, and the strategies and technology to meet these needs. This research identified the continued development of an omni-channel experience as a cross industry best practice to meet future customer needs. Continued investment in the DCX program is the cornerstone of the Company's broader onmi-channel investments.

- Project Relationships (if applicable): The DCX program is related to the AMI program and numerous clean enegy programs (e.g., Shared Solar program, REV Demonstration Projects, AMI Innovative Pricing Pilots, Energy Efficiency programs, etc.). Additionally, the DCX program will share a number of dependencies with new capital projects proposed in this filing including Virtual Assistants, Journey Mapping, Data and Analytics, and the New CSS Implementation program.

- Basis for Estimate: Capital costs are based on past DCX program costs. O&M costs are estimated based on a review of past program costs, Historic Year expenses, projected staffing needs, and ongoing software and labor costs to support associated IT infrastructure.

Total* Funding Level ($000):

Capital – Historical Elements of Expense ($000)
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Forecast 2018**
Labor		$509	$1,117	$1,688		$870
M&S		$186	$716	$65		0
A/P		$3,700	$7,107	$12,992		$8,046
Other		$85	$474	$1,607		$735
Overheads		$407	$678	$888		$434
Total		**$4,887**	**$10,092**	**$17,240**		**$10,085**

Capital – Future Elements of Expense ($000):

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	$805	$1,005	$1,000	$1,000	$625
M&S					
A/P	$6,428	$9,007	$9,260	$8,677	$3,231
Other	$525	$737	$737	$737	$398
Overheads	$2,319	$2,251	$2,003	$2,586	$2,746
Total	**$10,077**	**$13,000**	**$13,000**	**$13,000**	**$7,000**

O&M – Historical Elements of Expense ($000)
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor		$ 32	$ 97	$ 267	$650	$930
M&S						
A/P		168	1,000	4,889	5,804	5,424
Other		3	17	974	192	171
Overheads						
Total		**$ 203**	**$ 1,114**	**$ 6,130**	**$6,646**	**$6,525**

O&M – Future Elements of Expense ($000):

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	**$ 1,348**	**$1,043**	**$1,065**	**$1,087**	**$1,110**
M&S					
A/P	**4,588**	**5,513**	**5,643**	**5,779**	**5,923**
Other	**171**	**170**	**170**	**170**	**171**
Overheads					
Total	**$ 6,107**	**$6,726**	**$6,878**	**$7,036**	**$7,204**

*O&M Future Elements of Expense figures in 2020-2023 reflect the total O&M program funding net of BCO costs to achieve.

Digital Customer Experience Worksheet

Capital Cost Breakdown

Role	Count	Cost (avg. p/hr)	Total Cost
Company Program Management	3	$ 110.00	$ 594,000.00
SI & Design Agency Program Management	3	$ 175.00	$ 945,000.00
DCX Technical Architect	0.5	$ 75.00	$ 67,500.00
Project Managers	2.5	$ 175.00	$ 787,500.00
Scrum Masters	2.5	$ 87.50	$ 393,750.00
Product Owners	2.5	$ 95.00	$ 427,500.00
Business Analysts	3.5	$ 165.00	$ 1,039,500.00
API Technical Architects	2	$ 304.00	$ 1,094,400.00
API Developers	4	$ 80.00	$ 576,000.00
Biztalk Developer	2	$ 114.00	$ 410,400.00
End to End Testing Lead	1	$ 110.00	$ 198,000.00
End to End Testers	4	$ 90.00	$ 648,000.00
UX Lead	1	$ 175.00	$ 315,000.00
UX Designer	1	$ 175.00	$ 315,000.00
Content Strategist	0.5	$ 175.00	$ 157,500.00
Creative Design Resources(Lead, Designers, Illustrators, and Mobile Design)	3	$ 175.00	$ 945,000.00
Front End Lead	2	$ 75.00	$ 270,000.00
Sitecore Developers	3.5	$ 75.00	$ 472,500.00
Sitecore QA Analyst	1	$ 75.00	$ 135,000.00
Mobile Project Manager	0.5	$ 175.00	$ 157,500.00
Mobile Technical Architect	0.5	$ 175.00	$ 157,500.00
IOS/Andriod Lead	1	$ 175.00	$ 315,000.00
iOS Developer/Engineer	2	$ 175.00	$ 630,000.00
Android Developer/Engineer	2	$ 175.00	$ 630,000.00
Mobile QA Manager/Analyst	1.5	$ 175.00	$ 472,500.00
Marketing Sciences Director	0.25	$ 175.00	$ 78,750.00
Analytics Manager	1	$ 175.00	$ 315,000.00
Digital/Marketing Science Analyst	1	$ 175.00	$ 315,000.00
			$ 12,862,800.00

DCX Capital Cost Centers

Major Cost Centers	2019	2020	2021	2022	2023
Internal Labor	$ 805,000.00	$ 1,000,000.00	$ 1,000,000.00	$ 1,000,000.00	$ 645,000.00
Overheads & Indirects	$ 935,550.00	$ 1,247,302.87	$ 1,247,302.87	$ 1,247,302.87	$ 715,938.79
System Integrator & Design Agency	$ 3,400,000.00	$ 6,000,000.00	$ 6,000,000.00	$ 6,000,000.00	$ 3,000,000.00
Testing	$ 500,000.00	$ 610,000.00	$ 610,000.00	$ 610,000.00	$ 350,000.00
Biztalk	$ 150,000.00	$ 220,000.00	$ 220,000.00	$ 220,000.00	$ 150,000.00
Staff Augmentation	$ 2,500,000.00	$ 2,700,000.00	$ 2,700,000.00	$ 2,700,000.00	$ 1,500,000.00
IVR Development	$ 950,000.00	$ 1,200,000.00	$ 1,200,000.00	$ 1,200,000.00	$ 650,000.00
Total	**$ 9,240,550.00**	**$ 12,977,302.87**	**$ 12,977,302.87**	**$ 12,977,302.87**	**$ 7,010,938.79**

O&M Full Time Equivalent Requirements

DCX FTE Requirements (O&M)							
Organization	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Customer Operations	2	4	5	5	5	5	5
Information Technology	0.22	3.67	5	5	5	5	5
Public Affairs	1	2	3	3	3	3	3
Total	**3.22**	**9.67**	**13**	**13**	**13**	**13**	**13**

O&M Human Resources Roles

Information Resources	Customer Operations	Public Affairs
Digital Technology Lead	Digital Services Business Lead	Copy Writer
Digital Technology Architect/Leads	Digital Product Owner(s)	Content Authors
Senior Sitecore Developer(s)	Governance/Budget Specialist	
Senior .NET Application Developer(s)	Data Analyst (web analytics)	

DCX O&M Worksheet ($000's)

O&M	O&M Change 2020 (RY1)	O&M Change 2021 (RY2)	O&M Change 2022 (RY3)
Labor – Customer Operations	$178	$8	$8
Labor – Information Technology	$159	$9	$9
Labor – Public Affairs	$56	$5	$5
Software Maintenance Fees	$(314)	$130	$137
Total	$79	$152	$159

X	Capital
	O&M

2019 – Customer Operations

Project/Program Title	Journey Mapping
Project Manager	Rebecca Lessem
Hyperion Project Number	PR.22959952
Status of Project	In progress
Estimated Start Date	January 2018
Estimated Completion Date	December 2022
Work Plan Category	Strategic

Work Description:

Customer Operations proposes to continue investing in the Journey Mapping program to better understand customers' wants and needs, identify pain points, and increase opportunities to provide superior customer service for the seven core customer journeys identified below. In 2018, the Company launched two journey mapping teams. The first team started in January and is focused on customer 'Sign up for Service'. The second team began in March and is focused on the Company's 'Outage Communication' when customers have interruptions of their service.

Journey mapping is a process improvement method that explores the full sum of a customer's experience when interacting with a company, not just discrete interactions or transactions (referred to as customer touchpoints). A full customer experience, or "journey," is when a customer starts and finishes a transaction with no additional wants or needs from a company. For example, beyond looking at the discrete action of a customer requesting utility service with a phone call, a journey mapping team would review what caused the customer to call in the first place, the actual call experience, and any additional steps up to the point where the customer receives and understands their first bill.

Journey Mapping Process Overview

Unlike other process improvement techniques, journey mapping is entirely focused on the customer and is grounded in primary and secondary customer data, commonly referred to as Voice of the Customer ("VOC") data. VOC data incorporates customer research, benchmarking data, and operational data from a variety of sources including: Con Edison Advisory Community surveys, semi-annual customer satisfaction surveys, post transactional surveys, operational performance indicators, call volumes, customer complaints, and customer trends.

The journey mapping process begins with identifying the path that a customer takes to complete a transaction or obtain information. This allows the Company to better understand the number of steps that are required to complete the transaction in question. The process then overlays VOC data onto each step, which provides the customer's expectations, preferences, and aversions when evaluating an interaction, and helps Con Edison understand the customer's wants and needs for each decision point and touchpoint required to complete a transaction. Next, pain points for the experience are identified by analyzing what the customer is doing, what they are thinking, and their emotional state while completing a transaction. Taken together, these touch points provide a full picture of the experience, or journey that is being presented to the customer. The result of this work is considered a 'current state journey.'

Once the current state journey is defined, a series of workshops are held to create an aspirational journey that meets customer's wants and needs and addresses the pain points created by the current state journey. A root cause analysis is also performed on the identified pain points. Improvement projects are then defined and implemented to help achieve the aspirational customer journey. Typically, improvement projects are prioritized to address the root causes that have the greatest impact on customers and the Company.

The Company will incorporate customer research within each of these process steps. The Journey Mapping program will mainly leverage the online Con Edison Advisory Community as the participants of the customer research queries (whose participants statistically represent the Company's customer base). The research performed and the frequency of the studies depends on the depth of the VOC information that the Company has for a particular journey.

Proposed Key Journey Schedule

During Rate Years 1-3, the Company will undertake full journey mapping processes for seven journeys that represent the key interactions which drive customer satisfaction at Con Edison.[1] These journeys are listed below along with the expected timeline to map the journeys and implement improvements. The identification and prioritization of these journeys are based on a study performed by McKinsey & Company on customer journeys and their impact on customer satisfaction and business value. The following timelines depend on the complexity, customer impact, and number of pain points associated with the current state experience.

1. **Sign up for Service and Onboarding** – Started in January 2018. Current improvements are associated with creating more self-service options to start service with Con Edison
2. **Outage Communications** – Started March 2018. Current improvements are focused on delivering empathetic communications on customer's most preferred channels and increasing Estimated Time of Restoration transparency.
3. **Billing and Payment Assistance –** Planned to start in January 2019
4. **Billing and Payment Process –** Planned to start in 2019
5. **Energy Efficiency and Management –** Planned to start in 2019
6. **Emergency Services –** Planned to start in 2020
7. **Account Changes –** Planned to start in 2020

The Company is allotting approximately 1-3 years for each journey and is using an Agile approach (*i.e.*, an interactive and incremental method of designing, implementing, and testing work) to the prioritization and scope of each journey. Therefore, the prioritization and start date for each redesign may change based on business conditions and feedback from customers.

[1] For further information on the importance of these journeys to utility customer satisfaction see McKinsey & Company, The revival of customer loyalty: How regulated utilities can reshape customer engagement, A. Finegold, A. Pulido, S. Perl, May 2018
https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/the-revival-of-customer-loyalty

Improvements within each journey redesign are prioritized by the number of customers impacted and the implementation complexity. Once the initial improvements that affect most customers are implemented, journey teams begin to identify and implement improvements that affect smaller groups of customers or customer segments. This is done by reviewing the journey through the lens of archetypes of key customer segments called ‘personas.’ These personas focus on the different wants and needs that different customer segments have and are correlated to VOC and operational data. Improvements associated with specific personas create an additional layer of complexity to a process, but provide value to ensure that a single process or transaction results in different experiences for different users.

Implementing Journey Mapping-Driven Improvements

Funding for the Journey Mapping program will be utilized for labor associated with dedicated journey mapping team, as well as costs to implement the identified improvements. Improvements to the customer experience identified in the Journey Mapping program will require either minor changes to existing processes and experiences or major changes to an existing process, the creation of new processes, and/or building new system features.

The capital request outlined in this white paper will fund system changes identified as part of journey mapping. These investments will focus on the creation of new processes that did not exist before and investments in new systems that help the Company meet customers' expectations. Expenses will include company and third party labor for development and design of these changes, and any software or hardware costs. Examples of these capital improvements include (but are not limited to):

- Developing an engine to standardize payment agreements across all channels and predict when customers will be in need of payment agreements;
- Building a a process to allow customers to track inquiries on their repair process; and
- Hardware costs to enable facilitation of self service during face to face interaction with Company employees (i.e. outage response vans, and walk in centers). .

As described in the Customer Operations Panel testimony and the Justification Summary below, the Journey Mapping program will contribute to achievement of Customer Operations' Business Cost Optimization (“BCO”) Savings targets. All of the operations and maintenance (“O&M”) costs associated with this program are being treated as costs to achieve BCO savings, and have therefore been netted out of Customer Operations' total BCO savings target. As such this white paper does not include any O&M requests or corresponding program changes for this program.

Justification Summary:

Customers are increasingly comparing the experience with their utility to that of other industries such as banking and telecommunications. With its Journey Mapping program the Company aims to not only get to the heart of what customers want, but further, to provide optimal customer touchpoints.

Companies that consistently offer best-in-class customer experiences see a variety of business improvements associated with the increases in satisfaction and loyalty from consistent positive experiences. An analysis by McKinsey and Co. in 2017 showed that over a 4 year period, best-in-class customer experience companies saw increases in customer loyalty (up to 80% retention), higher success rates for cross-selling activities, reduction in call center volumes, and less marketing spend to drive growth.[2] By delivering consistent positive experiences across the seven key journeys, Con Edison expects to see similar results of increased engagement in energy efficiency offerings, Reforming the Energy Vision ("REV") projects, and self-service functionality.

The Company also benchmarked with other utilities across the country and found that FPL, Commonwealth Edison, PG&E, Duke Energy, Ameren, Consumers Energy, and others have started similar journey mapping projects. Improvements identified and implemented by these companies have delivered valuable improvements to customers, like Ameren's Outage Notification program where 94% of customers rated the improvement as valuable or extremely valuable.[3] Additionally, a European energy retailer's customer experience transformation grounded in journey mapping led to a 50% reduction in customer dissatisfaction with the utility's processes and a cost savings of €4 million in one year.[4]

The Company expects that its Journey Mapping program will result in the following benefits for Con Edison and its customers:

- New insights on what customers are looking for in terms of tools and experiences,
- Increases in customer engagement for clean energy products, new rate designs and other services due to an increase in trust and loyalty associated with improved customer experiences, and
- Reduction in calls due to more seamless and fulfilling customer interactions with re-designed journey experiences.

For example, in 2018 the Outage Communications journey mapping team conducted a survey of customers that experienced an outage in the past year. The findings indicated that a majority of customers want to communicate with Con Edison via text message but at the time of the survey only 140,000 customers were enrolled in Con Edison's outage text notification program.[5] The Outage Communications journey team is now working on a project to enable over 1,000,000 customers to report an outage via text message. Expanding the text notification program to approximately one-third of Con Edison's customers significantly enhances the impact of this self-service channel, and is expected to reduce the volume of emergency-related calls during a major outage event.

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[2] McKinsey & Company, Customer Experience Compendium, July 2017 https://www.mckinsey.com/~/media/McKinsey/Featured%20Insights/Customer%20Experience/CX%20Compendium%202017/Customer-experience-compendium-July-2017.ashx

[3] Ameren Corporation, CS Week May 2018 Presentation: Designing an Intentional Customer Experience During an Outage

[4] McKinsey & Company, The power of customer experience in energy retailing, Website Case Study https://www.mckinsey.com/industries/electric-power-and-natural-gas/how-we-help-clients/the-power-of-customer-experience-in-energy-retailing

[5] Con Edison JM Outage Report May 2018 FINAL, *Q8 – What is your preferred method to receive immediate communications from Con Edison during a storm power outage?* 67% of respondents (n= 423) preferred to receive via text message

Finally, the Journey Mapping program also supports the Company's BCO efforts to streamline processes and reduce costs. These savings are addressed in the BCO section of the Customer Operations Panel testimony.

<u>Supplemental Information</u>:

- <u>Alternatives</u>: Continue current state operations and processes where different departments are independently responsible for identifying and implementing customer experience improvements.

- <u>Risk of No Action</u>: General risks associated with not continuing the Journey Mapping program include:
    - Customers may continue to have repeated negative experiences from unidentified pain points resulting in decrease in satisfaction, loyalty, and trust
    - Future customer experience investments fail to take into account customer feedback and in-depth transactional insights
    - Customers continue to call the Customer Experience Center due to a lack of self service options for the most frequent customer interactions across each journey

  Journey-specific risks of no action will be identified as each customer journey and associated improvements are evaluated.

- <u>Non-Financial Benefits</u>: General non-financial benefits of the Journey Mapping program include:
    - Improved customer satisfaction through improved experiences and streamlined processes
    - Improved employee satisfaction due to improved customer experiences and reduction in labor
    - Improved customer engagement due to an increased willingness to participate in energy-related products and services offered by the Company as well as distributed energy resource providers

  Journey-specific non-financial benefits will be identified as each customer journey and associated improvements are evaluated.

- <u>Summary of Financial Benefits (if applicable) and Costs</u>: Please see the Customer Operations Panel testimony regarding BCO savings, as well as the Accounting Panel's testimony on the same.

- <u>Technical Evaluation/Analysis</u>: A comprehensive technical evaluation of the Journey Mapping program was completed during a Phase Zero analysis, which was completed in 2017. This evaluation was utilized as the basis for program scope, staffing, and cost estimates. In addition, customer research was conducted to inform the evaluation. The research confirmed customer expectations associated with the current state of the seven customer journeys and areas to look into when redesigning these journeys.

- <u>Project Relationships (if applicable)</u>: The Journey Mapping program will likely intersect with and/or is dependent upon the following Company programs and initiatives: Digital

Customer Experience ("DCX"), new Customer Service System ("CSS"), Virtual Assistants, Data and Analytics, BCO, Advanced Metering Infrastructure ("AMI"), Customer Outreach & Education, and Energy Efficiency. Additional project relationships may be identified as the program progresses with its in-depth journey evaluations.

- Basis for Estimate: The capital costs proposed in this white paper were forecasted based on historical capital costs for improvements in year 1 of the program, which is currently underway.

Total Funding Level ($000):

Capital - Historical Elements of Expense
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						$200
M&S						
A/P						$500
Other						
Overheads						
Total						**$700**

Capital - Request by Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	$400	$450	$300	$200	
M&S					
A/P	$2,300	$740	$675	$400	
Other					
Overheads					
Total	**$2,700**	**$1,190**	**$975**	**$600**	

Journey Mapping Process Overview and Benefits

Journey Mapping Process Overview

Establish Baseline	▪ Define customer personas and current state experiences for the applicable journey based on customer research and internal operational data
Envision Future State	▪ Establish scope for journey re-design (sub-journey(s), phases etc.) ▪ Re-map journey and identify ideas to eliminate pain points, create +1 experiences, and improve operational efficiency
Plan and Define Success	▪ Prioritize ideas based on the customer impact and complexity of each improvement idea ▪ Develop business cases for improvement opportunities requiring additional capital or O&M investment and seek approval ▪ Develop journey level success metrics and targets
Implement Roadmap	▪ Define execution plan, to incorporate frequent releases to maximize value ▪ Execute journey implementation plan using an agile approach
Monitor, Test, and Socialize	▪ Monitor journey level success metrics and targets ▪ Gather customer feedback on implemented ideas and add resulting actions to implementation backlog

Journey Mapping Benefits

Benefit 1: Insights on what customers are looking for in terms of tools and experiences
Journey maps will help identify gaps in customer service or communications by recognizing how different customer segments (or personas) want to interact with and receive information from the Company. A recent example of this arose when the 'Sign Up for Service' team's survey data highlighted that small business customers want easier and simpler ways to interact with Con Edison because the Company is one of many companies they need to interact with when moving to a new business location. To address this need, the journey mapping team collaborated with the DCX program to build a start service experience that allows small business customers to request their electric service online without having to speak with a Con Edison representative.

Benefit 2: Increased customer engagement due to improved customer experiences
A customer interaction may end when a customer hangs up their phone, closes their web browser, or leaves a building, but the customer experience does not have to end there. The follow up that occurs after a customer interaction could make the difference between a negative, neutral, or positive experience. It also presents an opportunity to build on positive experiences and engage customers on other Company offerings that were not directly related to the recently-concluded interaction. A recent example of this is the 'Sign Up for Service' team's creation of a new weekly 'welcome email series' for customers that open accounts with the Company. This program sends new customers information about billing, outage management, and energy efficiency programs that customers otherwise would have had to proactively seek out on their own.

Benefit 3: Reduction in calls to the Customer Experience Center
A majority of improvements identified through journey mapping tend to result in greater self-service opportunities for customers or proactive messaging. There are many case studies of these benefits in other industries – for example, telecommunications company Sprint has saved approximately $1.7 B per year by anticipating its customers' needs and providing effective non-call center based touchpoints to address those needs.[1] Expansion of self-service capabilities at Con Edison will not only increase customer satisfaction but also reduce call volume at the Company's Customer Experience Center.

[1] Urban Airship, Driving Profitability and ROI by Being Customer-Obsessed,T. Dengel, April 2018
https://www.urbanairship.com/blog/driving-profitability-and-roi-by-being-customer-obsessed

X	Capital
	O&M

2019 – Customer Operations

Project/Program Title	Virtual Assistants
Project Manager	Rebecca Lessem
Hyperion Project Number	PR.23242021
Status of Project	Initiation
Estimated Start Date	1/1/19
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

The Company proposes to invest in the Virtual Assistants program in an effort to expand communication channels with customers. A virtual assistant, or bot, is a conversational virtual agent that provides a unique, interactive, and personal way for customers to obtain answers and assistance across multiple channels, 24 hours a day, 7 days a week, 365 days a year. Investing in virtual assistant functionality as outlined in this white paper will provide the Company with a new form of frontline customer support that automates many of the simple interactions currently performed by Customer Service Representatives ("CSRs") on the phone and in the Company's existing live chat tool.

As part of the Virtual Assistants program, the Company plans to build and launch a number of bots that will interact with customers to answer specific customer inquiries. Utilizing a process called machine learning – a method of data analysis that automates analytical model building – each bot will use previous experiences and interactions to interpret customer inquiries and respond accordingly. The bots will be programmed to detect customer frustration and respond in an appropriate manner by interpreting cues such as customer responses written in all capital letters (among others). If a bot is struggling to answer a question, receives a question it is not trained to answer, or if a customer asks to interact with a live agent, it will also be able transfer a call or chat to a CSR.

During Rate Years 1-3, the Company plans to introduce bots of increasing complexity on multiple customer-facing channels on an iterative basis. This approach will allow the Company to gain experience with virtual assistant technology and adjust its bots along the way to sustain and improve customer satisfaction. Bots will be deployed via chat, interactive voice response ("IVR"), web/mobile web, mobile app, social media, and text. On each of these channels, the Company will focus on developing bots that can interact with customers to handle interactions such as:

- Identify/Authenticate Customer – confirm the customer identity and authenticate them for self-service use cases
- Create/Modify Payment Agreement – aid customers in creating and coordinating their payment agreement

- Stop Service – assist customers in setting up a stop service date
- Start Service – provide customers with self-service to start service and schedule or update field appointment for a new connection
- Transfer Service – assist customers in transferring their Con Edison services to another location
- Bill/Payment Inquiry – allows customers to inquire about their balance, due date, payment status, payment amount necessary to maintain service, and any other bill or payment related inquiries

The capital funding shown below will cover the purchase and installation of a virtual assistant artificial intelligence ("AI") program, and integrating that program with the following systems:

- Customer Information System
- CSR Desktop platform
- My Account web platform
- Mobile applications
- IVR
- Payment service systems
- Live chat and article suggestion platform
- Social media monitoring systems
- Email, phone and SMS communications platforms
- Smart home networks
- Enterprise data system and analytics tools (described in the Data and Analytics program white paper), and
- Enterprise knowledge management system (described in the Back Office Automation and Agent Tools program white paper).

Once the virtual assistant AI platform is integrated with these systems, the bots will be able to suggest Next Best Actions or communicate directly to CSRs or customers on behalf of the Company.

Justification Summary:

As customer adoption of digital solutions steadily increases, the Company faces a dynamic landscape of rising customer expectations, expanding channels of interaction, emerging technologies, and an evolving role as a trusted energy advisor. For example, business and residential customers alike expect proactive digital communication and prompt, competent service across channels at any hour of the day or night. Investing in the Virtual Assistants program will enable the Company to meet these rising expectations with modern, intelligent tools that continuously improve and learn with each customer interaction, and operate without the wait time a customer may experience waiting for a CSR through traditional interactions. For these reasons, investments in the Virtual Assistants program are a core component of the Company's overarching Next Generation Customer Experience initiative to deliver a seamless, low effort, high-satisfaction customer experience.

The Company's investments in virtual assistant and AI technology are a proven approach that is being adopted by best-in-class companies across industries, and supports emerging trends in customer interaction experiences. To inform development of this program, the Company performed benchmarking research across a variety of industry sectors and learned that virtual assistant technology is already changing the way many companies interact with customers. There are growing examples in the banking, retail, and telecom industries where virtual assistant technology has developed bots that can converse with customers and solve increasingly complex customer problems. For example, Bank of America recently introduced Erica, a virtual assistant that can handle customers' banking needs. In the utility sector, many companies – including WeStar Energy and TXU Energy– are now using virtual agents to provide personalized answers to billing questions or offer advice on energy efficiency opportunities. In fact, "83% of top European utilities executives [are] considering AI a high to medium priority for their business."[1]

In addition to supporting an improved customer experience, the Virtual Assistants program will enhance operational efficiencies by augmenting human capabilities and proactively solving a range of customer inquiries at every touchpoint, at any hour of the day or night. As the Company's virtual assistant capabilities become more advanced and customer adoption increases over the 2020-2022 time period, this program will begin to reduce the likelihood of a digitally-oriented customer needing to speak or chat with a CSR at all regarding a broad array of routine service matters. In addition,, virtual assistant technology will also assist the Company in achieving its Business Cost Optimization ("BCO") savings targets associated with contact prevention (see the Customer Operations Panel testimony on BCO savings for more information).

In summary, the Company's Virtual Assistants program combined with continued advancements in this proven technology will provide meaningful benefits to customers in terms of improvements in customer experience, and will also help the Company's efforts to reduce the cost to service customers.

Supplemental Information:

- Alternatives: Increase the number of CSRs dedicated to customer service (above the projections included in this rate filing) to meet growing customer expectations of prompt, intelligent service. This would erode the BCO savings achieved by Customer Operations.

- Risk of No Action: Customer satisfaction over time would decrease, as digital-first customers who are not able to resolve their inquiry via traditional, non-AI-enabled self-service channels (e.g., web, IVR, etc.) would only have the option of speaking with a CSR to complete a transaction. As customer expectations rise, the need to speak with a CSR (and any associated wait time) will frustrate these digital-first customers.

- Non-Financial Benefits: As noted above, the Virtual Assistants program will result in non-financial benefits such as increased customer satisfaction associated with improved, timely resolution of inquiries, on the customer's channel of choice.

[1] TechSee, Will bots process my electricity bill? AI transforming the CX for utility customers, Liad Churchill, May 1, 2018
https://techsee.me/blog/ai-in-utilities/

- Summary of Financial Benefits (if applicable) and Costs: As noted above, the Virtual Assistants program is expected to contribute to call deflection, as a result of fewer interactions requiring interaction with a CSR.

- Technical Evaluation/Analysis: The Company's approach to the Virtual Assistants program is based on a study being performed with a leading consultant in the customer experience space.

- Project Relationships (if applicable): The implementation of the Virtual Assistants program will require collaboration with multiple initiatives, including the Digital Customer Experience and Data and Analytics programs proposed by the Customer Operations Panel, and new Customer Service System program proposed by the Customer Energy Solutions panel. The Company considered these relationships in designing the Virtual Assistants program and will continue to manage these efforts in a manner that promotes the mutual success of all programs and mitigates stranded costs or redundant efforts.

- Basis for Estimate: The capital estimates below are based on expected employee labor costs and contract services associated with the expected capital expenditures to implement the Virtual Assistants program. These estimates are supported by the findings of the study performed by the Company.

Total Funding Level ($000):

Capital - Historical Elements of Expense
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P						
Other						
Overheads						
Total						

Capital - Future by Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor					
M&S					
A/P		$2,000	$2,000	$2,000	$1,000
Other					
Overheads					
Total		**$2,000**	**$2,000**	**$2,000**	**$1,000**

X	Capital
X	O&M

2019 – Customer Operations

Project/Program Title	Customer Bill Redesign
Project Manager	Raymond Joseph
Project Number	PR.23171780
Status of Project	In progress
Estimated Start Date	June 1, 2017
Estimated Completion Date	December 31, 2020
Work Plan Category	Strategic

Work Description:

The Customer Bill Redesign ("Bill Redesign") program proposes to implement changes to the customer bill and advance electronic delivery ("eDelivery") adoption. The program consists of two phases.

Phase 1, which spans June 2017 through the end of Q1 2019, has focused on researching bill design trends, analyzing customer feedback about the current bill and identifying bill enhancements that can be easily implemented, such as migrating away from background images, introducing color, and highlighting certain key information with boxes. These initial enhancements were implemented in stages between November 2018 and January 2019. During Phase 1, the Company also procured add-on modules to the existing Exstream software platform that generates customer bills, in order to increase operational flexibility and prepare for Phase 2. (Note: the Exstream platform was procured during the Company's last bill redesign effort which took place from 2006 to 2008.)

Phase 1: Bill Research and Initial Enhancements
June 2017 – 2018

- Utilized utility and telecom industry resources (e.g., Accenture, Info Trends, Chartwell, CS Week) to identify bill design best practices
- Conducted online customer surveys using the Con Edison Advisory Community ("Advisory Community") to gather feedback on billing and bill prototypes
- Conducted benchmarking exercises with PSEG Long Island and Commonwealth Edison
- Aligned bill redesign strategy across groups (i.e., Digital Customer Experience ("DCX"), Corporate Affairs, Law, Customer Outreach, Customer Assistance) for consistency across communications platforms, messaging and branding, and compliance with regulatory requirements
- Procured Exstream software add-on modules
- Conducted internal stakeholder workshops

Q1 2019

- Migrate printed bill to plain white paper
- Improve bill design and format to highlight bill amount and energy usage graphics

- Consolidate billing files to reduce the number of billing batches sent to vendor
- Consolidate bills and letters, which will streamline back office processes associated with collating batch files that were separately generated due to different paper forms

The Company began Phase 2 of the Bill Redesign program in January 2019. Phase 2 involves applying insights gained from Phase 1 research to develop prototypes of a newly rearranged bill design, testing the new design with Advisory Community surveys and customer focus groups, and coordinating with internal and external stakeholders to gain additional feedback and affirm compliance with regulatory requirements.

In coordination with the Journey Mapping and Data and Analytics programs, the Bill Redesign program will also evaluate customer adoption of eDelivery and propose strategies to encourage eDelivery adoption. The team will draw on insights from the upcoming Billing and Payments journey mapping exercise, which will review the customer experience for customers on eDelivery, explore barriers to adoption and identify solutions or tools to encourage eDelivery adoption. (See the Journey Mapping White Paper for further information about that program.) The Data and Analytics program proposed by the Customer Operations Panel will also play a role in developing propensity models to identify customers with a high likelihood to enroll in eDelivery. Using the results of the customer propensity models, the Company will develop targeted messaging to encourage eDelivery adoption among select customer groups.

Phase 2: Customer Bill Redesign and eDelivery Adoption (2019 – 2020)
- Conduct Billing and Payments journey mapping exercise
- Conduct internal stakeholder workshops
- Redesign bill and create prototypes
- Conduct customer feedback sessions on new bill prototypes
- Engage with external stakeholders to gather feedback on new bill prototypes
- Train CSRs on new bill designs

Taken together, these changes will update and modernize the paper bill so it is consistent with how bill-related information is presented on the Company's digital platforms, such as My Account. Paper bill upgrades will bring key customer information to the forefront, such as bill amount and payment due date, while maintaining all content required by New York State regulations. The program will also allow the Company to incorporate color graphics for easy viewing and understanding by customers.

The Rate Year 1 capital costs presented in this white paper include consultant labor to code and record software changes in the Exstream add-on modules, and one incremental full time equivalent ("FTE") to manage the software changes for all updates to the bill. The capital request is limited to Rate Year 1 only.

The operations and maintenance ("O&M") costs shown in the tables below include staff time to manage the project, expenses to support customer surveys and focus groups for feedback on bill changes, customer communications to encourage eDelivery adoption, contractors to maintain the Exstream software, and training for CSRs on changes made as part of the Bill Redesign program.

As described in the Customer Operations Panel testimony and the Justification Summary below, the Bill Redesign program will contribute to achievement of Customer Operations' Business Cost Optimization ("BCO") Savings targets. Fifty percent of the O&M costs associated with this program are being treated as costs to achieve Customer Operations' BCO savings targets. As such, the O&M costs shown below and the Customer Operations program change forms have been adjusted to reflect this treatment.

<u>Justification Summary</u>:

Research and benchmarking from Info Trends, Chartwell and industry peers at CS Week (an annual customer service conference attended by utility professionals across North America) indicate that, in general, utility billing statements should accomplish the following in order to satisfy customers:

- Be clear and simple to navigate and read
- Be more responsive to customer needs and focus on excellent customer service
- Provide relevant information (transactional, educational, regulatory and/or promotions) that provides value *within* the billing statement, as opposed to bill inserts
- Include useful analytics (*e.g.*, Smart Meter data via charts or dashboards)
- Utilize color printing to highlight important information
- For eDelivery customers, provide web addresses and embedded web links that facilitate customer self-service

Con Edison performed two surveys regarding existing bills via its online Advisory Community – one in 2017 for feedback on the bill and its contents, and one in 2018 for feedback on a bill prototype that was developed based on the 2017 survey results and broader industry research. The 2017 survey found that the information most important to customers pertains to current charges (*i.e.*, amount due, due date, charges, and usage), but this information is not always the easiest to find and customers want it to stand out more. Of the customers surveyed, 96% identified "Amount due" as extremely important, followed by "Charges" (92% of customers) and then "Due Date" (86% of customers). However, 70% of customers said "Amount Due" was easy to find, 54% of customers said "Charges" was easy to find, and only 47% of customers said "Due Date" was easy to find. Based on this initial feedback the Company created a prototype using plain white paper and highlighting amount due and due date in bold color blocks, and presented it for customer feedback. Most customers liked the prototype and found the actionable information easier to locate. Of the customers surveyed, 66% of customers liked that the "Amount Due" and "Pay By Date" were highlighted in the upper right-hand corner, versus only 1% of customers who did not like this change. The Company will continue to seek this type of iterative customer feedback throughout the Bill Redesign program.

By investing in further enhancements to both paper and electronic bills, the Company will provide to customers a bill that highlights the information they care about most, graphics for a quick understanding of their energy usage, and is consistent with how bill-related information is presented on the Company's digital platforms. As customers spend more time viewing their bills as an information resource and tool, the more likely these customers are to seek out products or services to help manage their energy usage, which in turn will support a wide range of clean energy programs and Reforming the Energy Vision ("REV") initiatives. By the end of this program at the end of Rate Year 1, the Company will be able to present customers with customized product suggestions and program offerings directly on the bill, further encouraging customer adoption of innovative solutions that make sense for their home or business.

The Bill Redesign program also supports the Company's BCO efforts to streamline processes and reduce costs. By migrating from pre-printed paper forms to a plain, white paper form, the Company will save in back office costs and materials. The efforts to increase customer eDelivery adoption will also help the Company reduce costs associated with postage from paper bill mailings. These savings are addressed in the BCO section of the Customer Operations Panel testimony.

In summary, continued investment in the Bill Redesign Program is necessary to provide customers with a bill that is easy to understand and encourages eDelivery adoption. The Bill Redesign program will result in a bill structure that is flexible and allows the Company to easily add or remove content, modify the placement of text boxes, update language to reflect new regulatory requirements, and change colors to emphasize key bill components. By responding to customer feedback and displaying energy bill and usage information in a simple format that highlights the information they care about, the Company can better engage with customers to facilitate adoption of REV programs. Also, while the Company seeks to invest in a new Customer Service System ("CSS") (as detailed in the Customer Energy Solution panel), continued investment in bill redesign will not result in any additional costs beyond the costs anticipated to integrate the existing Exstream software with the new CSS.

Supplemental Information:

- **Alternatives:** The only alternative to investing in bill redesign is to make limited updates to our current customer bills. Such limited updates will quickly become outdated as technology, bill design, and customer expectations evolve.

- **Risk of No Action:** If the Company does not take any action with respect to bill design, it will not keep pace with customer expectations of delivering a bill that is easy to understand and provides useful information that helps customers manage their energy usage. As the customer digital platform evolves while the paper bill stagnates, the customer could face a disjointed paper bill and digital experience that is confusing. It will also become increasingly difficult for the Company to modify its existing bills and rearrange content in response to new regulatory requirements.

- **Non-financial Benefits**: The Bill Redesign program will improve the customer experience with better information and a format that is easier to read and increase customer satisfaction.

- **Summary of Financial Benefits (if applicable) and Costs:** O&M costs stemming from the Bill Redesign program are described above. Savings associated with this program are addressed in the Customer Operations Panel testimony.

- **Technical Evaluation/Analysis:** To develop this program the Company conducted research using utility and telecom industry resources, such as Accenture, Info Trends, Chartwell, and CS Week to identify bill design best practices. The Company also benchmarked with PSEG Long Island and Commonwealth Edison.

  The Company also obtained customer feedback through its online Advisory Community, as described in the Justification section above.

- **Project Relationships (if applicable):** The Bill Redesign project is related to the DCX program, Journey Mapping, Data and Analytics, and the new CSS program proposed in the Customer Energy Solutions panel.

- **<u>Basis for Estimate</u>:** The cost estimates below were derived from analyzing the cost to achieve based on our industry peers, past project costs within Customer Operations, Information Technology, Corporate Communications, as well as external vendors that support our billing applications.

<u>Total* Funding Level ($000):</u>

<u>Capital – Historical Elements of Expense</u>
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1 million or more.)

EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Forecast 2018**
Labor						$110
M&S						
A/P						$40
Other						$850
Overheads						
Total						**$1,000**

<u>Capital – Future Elements of Expense</u>:

EOE	**Budget 2019**	**Request 2020**	**Request 2021**	**Request 2022**	**Request 2023**
Labor	$240	$240			
M&S					
A/P	$760	$760			
Other					
Overheads					
Total	**$1,000**	**$1,000**			

<u>O&M – Historical Elements of Expense</u>
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1 million or more.)

EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Forecast 2018**
Labor						$20
M&S						$130
A/P						
Other						
Overheads						
Total						**$150**

O&M – Future Elements of Expense:

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	$90	$57			
M&S		$30.5			
A/P		$25	$208	$208	$208
Other	$60	$87.5			
Overheads					
Total	**$150**	**$200**	**$208**	**$208**	**$208**

*O&M Future Elements of Expense figures in 2020 reflect total O&M program funding net of BCO costs to achieve.

Bill Redesign Worksheet

Bill Redesign Capital Worksheet ('000s)

Capital	Request 2020 (RY1)	Request 2021 (RY2)	Request 2022 (RY3)
Labor – Software Management	$240	$0	$0
Software development	$760	$0	$0
Total	$1,000	$0	$0

Bill Redesign O&M Worksheet ('000s)

O&M	O&M Change 2020 (RY1)	O&M Change 2021 (RY2)	O&M Change 2022 (RY3)
Labor – Project Management	$57	$(57)	$0
Customer surveys and focus groups, customer communications, and employee training	$143	$0	$0
Software maintenance	$0	$65	$0
Total	$200	$8	$0

X	Capital
	O&M

2019 – Customer Operations

Project/Program Title	Back Office Automation and Agent Tools
Project Manager	Rebecca Lessem
Hyperion Project Number	PR.23242008
Status of Project	Initiation
Estimated Start Date	1/1/19
Estimated Completion Date	12/31/22
Work Plan Category	Strategic

Work Description:

The Back Office Automation and Agent Tools program encompasses a collection of investments in software and new systems that will automate repetitive back office tasks, improve the accuracy and efficiency of exception management processes, enhance tools used by the Company's Customer Service Representatives ("CSRs"), and centralize knowledge sharing in order to provide more consistent experiences for customers and employees. Specific work streams include implementation of robotic process automation ("RPA") technology, a new exception management tool, and enhancements to the tools used to guide CSRs through customer interactions.

Robotic Process Automation – Currently, the Company primarily uses employees to carry out repetitive back-office tasks that involve making decisions based on set rules, and then taking an action. Examples of these back-office tasks include billing adjustments, processing account changes, or sending customer's a correspondence. These tasks are directed for employee intervention in the back-office because they are not able to be automated based on the need for a person to make decisions based on multiple factors and access information from multiple systems. Improvements in technology commonly referred to as "Robotic Process Automation" or RPA have made automating these tasks feasible due to their ability to build processes that take many business rules into consideration and perform actions across several software programs. For example, RPA tools could automate the process of inputting meter readings obtained in the field, into the Customer Information System ("CIS") to generate a bill for a customer. Currently a back office employee reviews these meter reading discrepancies each day, retrieves the meter reading from the meter reading reporting system each day and enters the readings into CIS to create a bill. An RPA tool has the ability to automate this process, which would allow for resolution in a quicker time frame and mitigate the potential for any customer impact.

The Company plans to implement a number of automation opportunities using RPA tools, based on a consideration of the overall effort involved in development of the RPA tool, and the associated customer satisfaction and cost saving value. High value use cases to be targeted were identified in a recent study and include, but are not limited to the following:

- Unbilled Accounts – currently, system estimates are disabled within CIS, which results in a manual process to review the unbilled account and enter an estimate for the account in order to bill. An RPA could query unbilled accounts in CIS and based on certain parameters, can automatically enter a bill code into CIS for billing.

- Customer provided meter reading – customers can provide their meter readings to the Company by sending a picture attachment in an email. CSRs currently need to manually process these meter readings by opening the email and picture attachment, and then entering the meter reading into an excel file. The meter reading is then uploaded into CIS. An RPA could automate all of the manual process steps.
- Inactive account meter readings – when a cycle reading posts or attempts to post on an inactive account and the reading difference exceeds a certain limit, an Account Investigation Listing ("AIL") is generated. A CSR would need to update the meter reading history in CIS on the previous account, issue a no charge final bill, reset the start reading on the inactive account, and post a bill memo. An RPA could automate all of the manual process steps.

Exception Management Tool – Back office exceptions which cannot be automated using RPA tools must be worked in an efficient and intelligent manner. These exceptions include bills which require review of adjustments, account discrepancies (such as meter, rate class or billing option), and special cases such as escalated customer inquiries. The Company plans to replace the current exception management system, which is based on outdated technology that can no longer be supported. The Company will invest in a new exception management tool that will give supervisors the ability to efficiently identify, prioritize and route exception work to employees. In addition, the system will allow for creation of dashboards which allow supervisory oversight of pending work. For example, the exception management tool will allow for pending work units to be obtained from various systems, for prioritization of work units based on configurable factors, and assignment to employees by the Supervisor. Once work is assigned, employees can retrieve the work from the exception management tool and complete work.

After selecting exception management software, the Company will integrate it with the existing CIS. The selection and procurement of the proper exception management tool will be complete by the end of 2020, at which point the Company will begin phasing in integration of current exceptions, and developing plans to integrate with the new Customer Service System ("CSS") (as detailed in the Customer Energy Solution Panel testimony) when ready. A gradual phase-in of the new exception management tool will ensure our continued speed of customer service. The Company anticipates completing the transition to the new exception management tool, including creating new management workflows in addition to existing procedures, by 2022.

Customer Service Representative Tools – When the Company's CSRs are interacting with a customer, they utilize various tools, collectively described as a "desktop" program overlaying the CIS that contains account information, shortcuts, conditional scripting to facilitate responses to inquiries and execution of transactions. The Company seeks to make a number of enhancements to the CSR desktop in order to improve a CSR's ability to effectively and efficiently provide service to customers. Enhancements include incorporation of improved visibility into customer related data from other systems, such as programs and communications preferences the customer is currently enrolled in. In addition, the Company will continue to work to streamline process flows and add controls to CSR tools. Finally, the Company plans on investing in knowledge management ("KM") tools, which would be the single system for CSRs and other employees to quickly access information, procedures and policies relating to customer queries. For example, a CSR handling an inquiry regarding customer claims would be able to search for this content (similar to internet searches such as Google) and quickly identify the appropriate information, including the types of claims, customer eligibility, claims forms and specific information which should be provided to the customer. Management employees would have the ability to make the content engaging to improve employee understanding, and easily manage and modify the content as policies and procedures change. The Company will procure one or more off-the-shelf software solutions that will facilitate improved management of knowledge.

Con Edison looks to implement the following investments over the next 4 years:

- 2020
  - Operationalize top value RPA use cases
  - Procure and implement of exception management tool
  - Convert content to knowledge management software
- 2021
  - Incorporate improvements to the information a CSR sees on their desktop related to data from ancillary customer systems.
  - Complete transition of existing processes to new exception management tool
  - Additional use cases added to RPA tool

- 2022
  - Coordinate knowledge management roll out with new CSS Incorporating knowledge management into the CSR desktop
  - Additional processes added to new exception management tool

The capital funding requested in this white paper includes funding for software costs for an exception management tool and knowledge management tools, as well as labor associated with development of CSR tools. As described in the Customer Operations Panel testimony and the Justification Summary below, the Back Office Automation and Agent Tools program will contribute to achievement of Customer Operations' Business Cost Optimization ("BCO") Savings targets. All of the O&M costs associated with this program (including RPA licenses and development) are being treated as costs to achieve BCO savings, and have therefore been netted out of Customer Operations' total BCO savings target. As such this white paper does not include any O&M requests or corresponding program changes for this program.

Justification Summary:

In order to provide a seamless, positive customer experience while also reducing costs, efficient back office processes and empowered employees with the proper tools are essential. The Company's investment in the Back Office Automation and Agent Tools program will support its overall goal of providing a next generation customer experience by creating streamlined and consistent processes, facilitating satisfying customer interactions, and driving cost savings that will benefit all customers.

RPA

RPA provides new opportunities to automate work, which today requires manual review by an employee working in the back office. Automation of back office work is essential for two reasons. First, RPA can complete back office tasks in a fraction of the time it takes for an employee to review. As a result, backlogs of automated back office work (such as bills requiring adjustments) will essentially be eliminated, resulting in operational efficiency in terms of reductions in resolution time, which is a key benefit for customers. Second, automation of back office work provides the benefit of O&M cost reductions for work which is automated, as it eliminates the costs associated with manual review by an employee.

Exception Management Tools

Currently, the Company utilizes an exception management system called Forest and Trees that links to the current CIS to generate reports that facilitate management of back office processes such as review of shared meter cases, interdepartmental referrals (i.e., request for review of unhonored payments), and account citations (such as required billing adjustments) . Forest and Trees is an outdated system that is no longer supported by the vendor, and has limited functionality, which requires supervisors to manually assign work and employees to manually track completed work. Upgrading to a new exception management reporting tool will allow the Company to ensure continued viability of back office system work needs and enhance management of back office work which will allow for quicker customer billing corrections and improved customer experiences.

CSR Tools

Enhancements to CSR tools will facilitate customer interactions, enabling quicker responses to inquiries and completion of transactions. Desktop enhancements will provide the CSR with a quick reference to critical customer information and past interactions.

Development of a KM tool will integrate information in an organized and easy to access format, allowing for faster resolution of customer inquiries. In addition, a KM tool will allow for faster creation and management of content by administrators. Speed of creating new knowledge content is critical to providing CSRs timely information on new clean energy programs associated with energy efficiency, Reforming the Energy Vision ("REV"), and distributed generation.

In addition to the operational benefits outlined above, the Back Office Automation and Agent Tools program is a key enabler of the Company's BCO goal of reducing operating costs. Continued investment in streamlined back-office work processes and information retrieval proposed in this white paper are essential to achieving the workforce management and back office automation goals outlined in the Customer Operations Panel's BCO testimony. Without investment in our automation and agent tools, the Company will not be able to achieve savings identified in the BCO sections of the Customer Operations Panel testimony and the Accounting Panel testimony.

In summary, investment in the Back Office Automation and Agent Tools program will streamline and improve the Company's internal customer service-related processes to enable employees to focus more on customer care. This will result in improved work quality, increased productivity, and operational efficiencies, which in turn will result in operational savings and an improved customer experience that will benefit all customers.

Supplemental Information:

- Alternatives: For RPA, the alternative is to continue the current process of having employees review all back office work, which would not allow for the realization of cost savings and resolution time benefits. For exception management tools, the alternative would be to continue to use an outdated management system no longer supported by the vendor (Forest and Trees) to manage work, resulting in associated risk of continued viability. For CSR tools, the alternative is utilizing current tools and failing to improve while customer expectations rise, which would negatively impact customer satisfaction.

- Risk of No Action: The risk of no action for enhancement in back office and agent tools, is not meeting customer expectations for prompt, accurate service. In addition, the risk of no action is not realizing the operational costs cost savings associated with a more automated and efficient back office.

- Non-Financial Benefits: There are a number of non-financial benefits associated with the Back Office Automation and Agent Tools initiative, as noted throughout this white paper. These include increased customer satisfaction through faster resolution of inquiries handled by CSRs when speaking to customers and when resolving back office work.

- Summary of Financial Benefits (if applicable) and Costs: O&M savings from the Automation and Agent Tools program are addressed in the BCO sections of the Customer Operations Panel testimony and Accounting Panel testimony.

- Technical Evaluation/Analysis: An analysis of RPA opportunities was completed by a consultant in 2018. The analysis identified the back office work which was feasible for automation and the work was prioritized based on the potential benefits.

- Project Relationships (if applicable): The Back Office Automation and Agent Tools program is related to the Digital Customer Experience ("DCX") program as many of the same tools provided to customers online, will be utilized to enable CSRs to resolve customer inquiries by phone. For example, the ability for CSR to set communication preferences on behalf of the customer, utilizing the DCX preference center.

- Basis for Estimate: These estimates are based on past costs for similar efforts, and benchmarks and analysis from experienced consultants.

Total Funding Level ($000):
Capital - Historical Elements of Expense
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Forecast 2018**
Labor						
M&S						
A/P						
Other						
Overheads						
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

Capital - Future Elements of Expense

EOE	**Budget 2019**	**Request 2020**	**Request 2021**	**Request 2022**	**Request 2023**
Labor					
M&S					
A/P		$2,000	$2,000	$200	
Other					
Overheads					
Total		$2,000	$2,000	$200	

	Capital
X	O&M

2019 – Customer Operations

Project/Program Title	Advanced Metering Infrastructure (AMI) Savings
Project Manager	Chris Grant
Project Number	N/A
Status of Project	In progress
Estimated Start Date	2/2015
Estimated Completion Date	12/2023

Work Description:

Con Edison is currently deploying Advanced Metering Infrastructure ("AMI") across its service territory until 2022 as approved by the Public Service Commission ("Commission"). The scope of work for the AMI program includes the following:

- Building the AMI Information Technology ("IT") platform and developing the system interfaces between the AMI IT platform and legacy applications,
- Installing the AMI communications network for territory-wide coverage, and
- Installing approximately 3.6 million electric smart meters, retrofitting 1 million gas meters with AMI modules and replacing approximately 180,000 tin case gas meters that cannot be upgraded with a new meter and AMI module.

For the full scope of details on the AMI program, please refer to 1) the Company's AMI Business Plan[a], 2) the Commission's *Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions*,[b] issued in March 2016 in the same case, 3) the Commission's *Order Approving Gas and Electric Rate Plans*[c] , and 4) the Company's AMI metrics reports filed in the 2016 Rate Proceedings. Please also refer to the Customer Energy Solutions Panel testimony for further information on the Company's proposal for continuation of the AMI program during the 2020-2022 time period.

As stated in the AMI Business Plan and 2016 Rate Proceedings, the AMI program will result in significant operations and maintenance ("O&M") cost reductions for the Customer Operations

[a] Case 15-E-0050, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service ("2015 Rate Case")(filed November 16, 2015).
[b] 2015 Rate Case Proceeding, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions ("AMI Order")(issued March 17, 2016).
[c] Case 16-E-0060 et al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Approving Gas and Electric Rate Plans ("2016 Rate Proceeding")(issued January 25, 2017).

organization. These reductions include labor and associated operational expenses[d]. The AMI-driven O&M savings projected for Customer Operations during the 2020-2022 time period are predominantly comprised of labor savings in the following areas: Meter Operations, Field Services, the Customer Experience Center, Billing, and Replevin.

- Labor O&M Reductions
  - Meter Operations: Reduction in meter reader full time equivalent ("FTE") staffing
  - Field Services: Reduction in FTE staffing - includes turn-on / turn-off ("T&T") staff, Special Forces staff (includes Replevin), Collections staff, and supervisory staff
  - Customer Experience Center: Reduction in call volume translated into FTE staffing - includes reduction in account investigation listings ("AILs"), meter reading and estimated read calls, T&T calls, and high bill complaint calls
  - Billing: Reduction in call volume and work associated with billing AILs, and avoided PSC complaint costs, translated into FTE staffing

Taken together, these labor savings make up approximately 99% of Customer Operations' total AMI-related O&M reductions each year in the 2020-2022 time period.

The Company also expects the AMI program to drive non-labor reductions in O&M costs associated with Replevin during the 2020-2022 period.

- Non-Labor O&M Reductions
  - Replevin: Reductions in administrative fees (such as court index numbers) associated with Replevin

These non-labor savings account for 1% of Customer Operations' total AMI-related O&M reductions in each year in the 2020-2022 time period.

Customer Operations' total AMI-related O&M cost reductions are summarized in the table below for Rate Years 2020-2022.

(in '000s)	RY1 2020	RY2 2021	RY3 2022
Labor	$(19,316)	$(31,435)	$(38,750)
Non-Labor	$(183)	$(258)	$(293)
Total	$(19,499)	$(31,693)	$(39,043)

It should also be noted that the AMI-related O&M savings identified in this white paper (and associated testimony and program change forms) are separate and distinct from the Business Cost Optimization ("BCO") savings described in testimony of the Customer Operations and Accounting Panels.

[d] Uncollectable bill ("UB") reductions were identified in the 2016 Rate Case as Customer Operations savings, but as UB is a corporate expense that does not impact the Customer Operations budget, it is not included in this white paper.

Justification Summary:

As described in the Company's AMI Business Plan and reiterated in the preceding section, the transition to AMI is profoundly changing the process of metering from a manual process to an automatic process. In addition to dramatically reducing the meter reading forces needed to physically visit – or drive by – nearly all meters in the Company's service territory on a monthly basis, AMI will also lower the number of metering-related issues that must be handled by Customer Service Representatives ("CSRs") and back office personnel and the amount of resources dedicated to collecting unpaid bills associated with meters that the Company is unable to access.

Supplemental Information:

- Alternatives: Now that the AMI program is underway, the only alternative would be to cease deployment at the end of 2019. In preparing its AMI Business Plan the Company evaluated multiple alternatives to a territory-wide AMI rollout and determined that there are a number of benefits that would *not* be realized by a partial or non AMI deployment. In addition to foregoing all of the Customer Operations savings described in this white paper, Con Edison would not be able to meet a number of REV objectives in a cost effective manner. Additional benefits that would not be realized without AMI include (but are not limited to): inability to provide near-real time granular metering data required for customers to make informed energy choices, and reduced ability to leverage AMI technology for outage detection and emergency response, conservation voltage optimization, and system planning.

- Risk of No Action or Delayed Action: See "Alternatives" section above.

- Non-financial Benefits: Please see the Company's AMI Business Plan for further information on non-financial benefits of the AMI program.

- Summary of Financial Benefits (if applicable) and Costs: The Company estimated in its AMI Business Plan that total cost saving and cost reduction benefits due to full AMI program implementation have an impact of $2,706 million NPV over the 20-year evaluation period. Cost savings and cost reduction benefits specific to Customer Operations during the 2020-2022 time period are described above and also laid out in the tables below.

- Technical Evaluation/Analysis: Please refer to the AMI Business Plan for details on the Company's technical evaluation and benefit-cost analysis of its AMI program.

- Project Relationships (if applicable): Customer Operations' AMI-related savings are dependent on the success and timely implementation of the AMI program, including both meter deployment and completion of all related IT and communications infrastructure.

- Basis for Implementation Estimate: In estimating Customer Operations' AMI-related O&M reductions, the Company took into consideration all aspects of the AMI program that would impact Customer Operations' work volumes and ongoing operating costs as described in the "Work Description" section above. Based on this impact assessment, Customer Operations quantified the labor-related benefits of AMI by translating reduced work volumes into estimated FTE reductions. Non-labor cost savings were estimated based on corresponding projections of meter reading system support needs.

Total Funding Level ($000):

Historical Elements of Expense

(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Forecast 2018**
Labor						$(1,121)
M&S						
A/P						
Other						
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**$(1,121)**

Future Elements of Expense

EOE	**Budget 2019**	**Request 2020**	**Request 2021**	**Request 2022**	**Request 2023**
Labor	$(7,384)	$(19,316)	$(31,436)	$(38,751)	$(39,545)
M&S					
A/P	$(106)	$(183)	$(258)	$(293)	$(293)
Other					
Overheads					
Total	**$(7,490)**	**$(19,499)**	**$(31,694)**	**$(39,044)**	**$(39,838)**

Advanced Metering Infrastructure Savings Worksheet

AMI Savings Worksheet ('000s)

O&M Savings	**O&M Change 2020 (RY1)**	**O&M Change 2021 (RY2)**	**O&M Change 2022 (RY3)**
Labor – Meter Operations	$(13,686)	$(8,340)	$(4,727)
Labor – Field Services	$(4,390)	$(3,051)	$(2,154)
Labor – Customer Experience Center	$(963)	$(522)	$(435)
Labor – Billing	$(277)	$(207)	$0
Replevin Administrative Fees	$(183)	$(75)	$(35)
Total	$(19,499)	$(12,195)	$(7,350)

	Capital
X	O&M

2019 – Customer Operations

Project/Program Title	Credit and Debit Card Fee Elimination
Project Manager	Robert Buck
Hyperion Project Number	N/A
Status of Project	Initiation
Estimated Start Date	1/1/2020
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

<u>Work Description</u>:

The Company proposes to eliminate the credit card and debit card ("CC/DC") transaction fees that are currently charged directly to residential and small commercial customers by the Company's payment processing vendor in Rate Year ("RY") 1, and incorporate the aggregate costs associated with these transactions in base rates in the same year. (This is referred to as a 'no-fee model' for CC/DC payment.)

The Company recently completed a Request for Proposals seeking competitive CC/DC transaction fee rates from payment processing vendors. In January 2019, the Company selected a payment processing vendor and secured a reduced CC/DC fee of $2.10 per transaction for residential and small commercial customers effective in RY 1. This lower fee is conditional on Commission approval of the proposal set forth in this white paper to transition to a no-fee model. If approved, the lower fee would translate to a 37% reduction over the current fee of $3.35 per transaction that customers pay directly to the Company's vendor. Additionally, if the Commission approves the transition to a no-fee model, customers will be able to schedule recurring payments using the CC/DC payment option; previously recurring CC/DC payments were not possible because customers must accept the transaction fee with each new payment.

Under the new contract, large commercial customers will continue to pay a per-transaction fee directly to the vendor equal to 2.6% of the payment amount, regardless of the outcome of this proposal.

Under the current CC/DC payment model 5.4% of all payments were made via CC/DC on average per month from October 1, 2017 through September 30, 2018. Residential and small commercial customers accounted for 98% of these transactions. Based on benchmarking data provided by its payment processing vendor, the Company expects to see a 47% increase in payments made via CC/DC under a no-fee model in RY1, and incremental increases of 31% and 10% in RY2 and RY3, respectively. Residential and small commercial customers are expected to account for the same or higher percentage of total CC/DC payments across all three Rate Years. The following table presents the expected number of residential and small commercial CC/DC transactions per year under a no-fee model, and the aggregate costs that would be included in base rates.

	No. of Residential & Small Commercial CC/DC Payments	Per-Transaction Cost	Aggregate Cost Included in Base Rates
October 1, 2017 – September 30, 2018	2,032,266	$3.35	Not Applicable
Rate Year 1 (2020)	2,987,431	$2.10	$6,273,605
Rate Year 2 (2021)	3,913,535	$2.10	$8,218,424
Rate Year 3 (2022)	4,304,888	$2.10	$9,040,265
Total RY 1-3	11,205,854	N/A	$23,532,293

Justification Summary:

Credit and debit cards have become one of the most common payment methods in the United States for a variety of reasons, including their convenience to consumers. According to the 2016 Federal Reserve Payments Study, card payments accounted for 72% of the total number of non-cash payments in 2015, up from 39% in 2000. From 2000 to 2015, the number of noncash payments made using prepaid, debit and credit cards increased by 78.9 billion payments, while check and ACH payments decreased by 7.8 billion payments.[1]

Additionally, in the Federal Reserve Payments Study: 2017 Annual Supplement, credit card payments had the highest growth rate by payment type from 2015 to 2016, increasing 10.2%, while debit card payments had the second highest growth rate of 6% during that same period.[2]

Customers expect their utility to provide billing and payment options on par with the options available in their other day-to-day transactions, such as paying a wireless bill or medical bill. According to a 2016 Residential Consumer Survey by Chartwell – a specialized information provider for the utility industry – easy billing and payment is the number one driver of customer satisfaction. Chartwell's 2018 Residential Consumer Survey, an online survey of U.S. and Canadian energy consumers, also found that waiving CC/DC fees can increase customer satisfaction.

The Company has also received direct customer feedback regarding CC/DC fees through its quarterly customer experience surveys. These surveys – which draw from Con Edison's online Advisory Community as well as customers who have had an interaction with the Company within the past three months – include the following open-ended question: "How can we improve your overall experience with Con Edison?" Consistently, one of the top responses to this question in the 2018 surveys was that the Company should allow for CC/DC payments without a fee.

1 https://ritholtz.com/2017/05/evolution-not-revolution-payments-undergoing-changes-united-states/
2 https://www.federalreserve.gov/newsevents/pressreleases/files/2017-payment-systems-study-annual-supplement-20171221.pdf

The Company believes transitioning to a no-fee model will also enhance the customer experience for our customers who receive public assistance benefits via pre-paid EBT debit cards. Under the current model, such customers can pay their utility bill with their pre-paid debit card, but must use a portion of their benefits to cover the vendor fee for CC/DC payments. Adopting a no-fee model will eliminate allow this sensitive customer population to use all of their benefits for payment assistance. The proposed change will also benefit our overall low income customer population: recent data indicates that approximately 8% of customers enrolled in the Company's Low Income Programs choose to pay their bill with a CC/DC (i.e., approximately 32,505 payments per month for 430,000 customers). Using the current fee of $3.35 per payment, the impact of a no-fee model for these customers would be an avoided out-of-pocket cost of $1.3M annually.

Additionally, offering a no-fee model at Con Edison is consistent with the Commission's recent approval of similar models at Central Hudson Gas and Electric Corporation[3], New York State Electric and Gas Corporation, and Rochester Gas and Electric Corporation [4].

Finally, increased payment by CC/DC has operational benefits, including a reduction in returned payments and faster same-day payments. Currently, the percentage of CC/DC payments returned is 0.17 percent, compared to 0.82 percent for check payments – with increased payments made through CC/DCs, the Company anticipates a reduced number of returned payments. Additionally, a 2014 study by Fiserv, a CC/DC payment processing vendor, showed that across 105 utilities, transitioning to a no-fee model led to increased use of lower-cost self-service payment options, specifically more web payments and recurring payments. Also, in some cases customers contact the Company's Customer Experience Centers to confirm that a payment has been credited to their account. This additional call will be unnecessary if customers set up recurring CC/DC payments.

<u>Supplemental Information</u>:

- <u>Alternatives</u>: Continue to offer residential and small commercial CC/DC payments for a fee paid directly to a third-party vendor.

- <u>Risk of No Action</u>: Continued customer dissatisfaction with CC/DC payment fees and missed opportunities to engage additional customers in self-service and recurring payment options. Also, continuing to charge public assistance customers a transaction fee that erodes the benefits they may receive on pre-paid debit cards is a costly option for these customers.

- <u>Non-financial Benefits</u>: With implementation of the no-fee model, the Company anticipates increased customer satisfaction, opportunity to enroll additional customers in self-service and recurring payment options, modest call deflection from avoided payment confirmation calls, reduction in returned payments and faster same-day payments.

- <u>Summary of Financial Benefits (if applicable) and Costs</u>: O&M costs associated with this program are included in the tables below.

[3] Case 17-E-0459 et.al, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, *Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan* (Issued and Effective June 14, 2018)/

[4] Case 15-E-0283 et.al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service, *Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal* (Issued and Effective June 15, 2016).

- Technical Evaluation/Analysis: N/A
- Project Relationships (if applicable): N/A
- Basis for Estimate: The Company's CC/DC transaction growth forecast (i.e., 47% Rate Year 1, 31% Rate Year 2, 10% Rate Year 3) derived from vendor-provided data from other industries that went to a no-fee model. Costs taken from vendor quote.

Total Funding Level ($000):

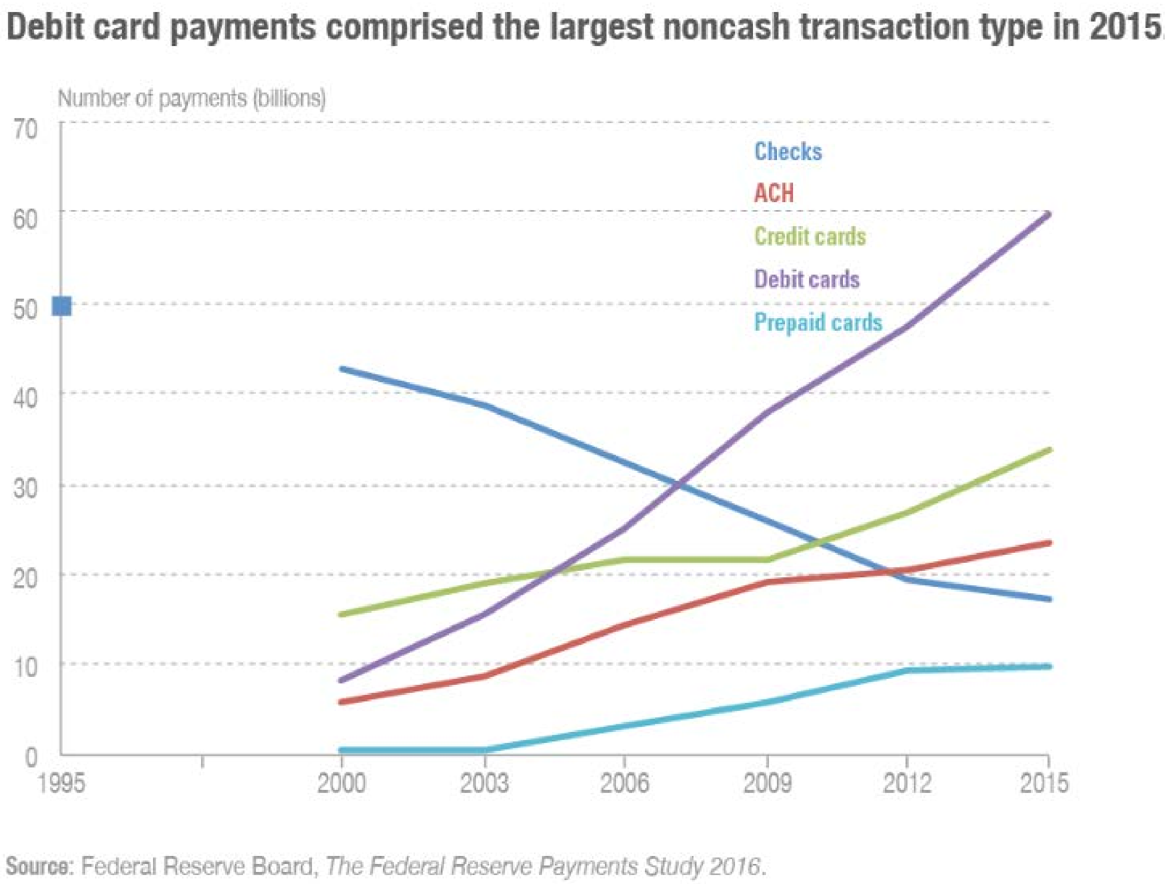
O&M - Historic Elements of Expense
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Historic Year** (O&M only)	**Forecast 2018**
Labor						
M&S						
A/P						
Other						
Total						

O&M - Future Elements of Expense

EOE	**Budget 2019**	**Request 2020**	**Request 2021**	**Request 2022**	**Request 2023**
Labor					
M&S					
A/P		$6,273	$8,218	$9,040	$9,944
Other					
Overheads					
Total		**$6,273**	**$8,218**	**$9,040**	**$9,944**

2016 Federal Reserve Payments Study



Source: https://ritholtz.com/2017/05/evolution-not-revolution-payments-undergoing-changes-united-states/

Credit and Debit Card Fee Elimination Worksheet
('000s)

O&M	O&M Change 2020 (RY1)	O&M Change 2021 (RY2)	O&M Change 2021 (RY3)
Credit and Debit Card Processing Fees	$6,273	$1,945	$822
Total	$6,273	$1,945	$822

X	Capital
	O&M

2019 – Customer Operations

Project/Program Title	Customer Experience Center Disaster Recovery
Project Manager	Sebastian Cacciatore
Hyperion Project Number	PR.23330608
Status of Project	Initiation
Estimated Start Date	January 2020
Estimated Completion Date	December 2020
Work Plan Category	Strategic

Work Description:

The Customer Experience Center Disaster Recovery program is one of Customer Operations' operational priorities, as explained in the Customer Operations Panel testimony. In this program, the Company proposes to harden its Internet Protocol ("IP") telephony system to maintain operational reliability when multiple events, such as cyber attacks or physical disasters, occur that affect the Company's network infrastructure.

In May of 2015, the Con Edison Customer Experience Centers ("Call Centers") implemented a new IP telephony system to process all inbound and outbound voice customer service transactions, including electric, gas, and steam emergency calls. The IP telephony system enables a single routing engine to handle multiple communication streams simultaneously – *e.g.*, live agent phone calls, interactive voice response ("IVR") transactions, and email communications – and includes an array of functionalities enabling call recording, real-time monitoring of call queues, performance reporting, workforce scheduling, and IVR self-service capabilities. The IP telephony system also processes inbound and outbound phone calls for multiple departments outside of Customer Operations, including the Information Technology Helpdesk, Human Resources Service Center, and Employee Wellness Center.

In total, the IP telephony system processes nearly 100 million minutes of voice traffic annually. In addition to the millions of customers who interact with the IP telephony system each year, more than 1,100 Company employees utilize the system to perform their core job functions. During times of high call volume – and in particular during system emergency events – the IP telephony system serves as an essential channel for the Company to relay important information to its customers and stakeholders, and allows customers to continue performing basic transactions on the IVR while live agents handle emergency-related calls.

The IP telephony system is supported by two physically separated server farms, both located at Company facilities. These server farms are both capable of processing 100% of the transactions on the Company's voice, IVR and email communications streams. The IP telephony system is designed with redundancy and diversity, a single contingency architecture that preserves system availability in the event of a component failure. During normal system operations, call traffic is processed across both server farms. In the event that one of the server farms supporting the IP telephony system experiences an outage, all call traffic is automatically processed via the alternate location.

The goal of the Customer Experience Center Disaster Recovery program is to harden the IP telephony system to maintain operational reliability when multiple events such as cyber attacks or physical disasters occur that affect the Company's network infrastructure. The IP telephony system is not currently designed to endure two simultaneous events ("double contingency events") that might damage or compromise operation of both server farms at the same time. While double contingency events are unlikely, they could have a devastating effect on the Company's ability to effectively assist customers with system-related emergencies, such as power outages or gas leaks, and receive customer service inquiries.

The funding requested in this white paper will be utilized to implement robust risk mitigation solutions that will further harden the IP telephony system against double-contingency events by the end of Rate Year 1. The Company will perform a comprehensive analysis of potential solutions in 2019 – including a combination of off-premise telephony design options – and will select a technology solution based on project feasibility, cost, time to implement, and integration compatibility with existing systems. Most importantly, the off-premise disaster recovery solution (e.g., cloud-based or software as a service) will be hosted by a qualified vendor and will integrate with the Company's customer information systems. Furthermore, the disaster recovery solution will be designed to mirror the applications currently residing on the IP telephony system and will be activated on demand, or when necessary. The Company will provide additional information on this assessment in its update testimony.

Justification Summary:

With this proposal, the Company is taking a proactive stance to maintain reliable operation of its mission-critical IP telephony system. As stated above, if simultaneous outage events were to occur in the current environment, the IP telephony system would go offline and customers would not be able to reach the Company's Call Centers via phone or email. This means customers would not be able to report emergencies or perform important customer service transactions over the phone – such as making payments, obtaining payment agreements to avoid disconnection, and working to resolve billing anomalies – in the language of their choice.

In the worst-case scenario of a double contingency IP telephony system event combined with an electric, gas or steam system emergency, the impact on customers could be particularly far-reaching. For example, this combination of events could: prevent the Company from learning about or responding to situations that threaten public safety, result in substantially lower volumes of customer-reported outages that aid in damage assessment and restoration planning, and/or dramatically increase customer confusion and frustration with the Company's outage restoration plans.

Cyber attacks on utilities have become more prevalent in recent years, raising significant concerns among corporations and governments alike because of the impact such attacks could have on the power grid as well as utility customer service infrastructure. Due to the surreptitious nature of cyber attacks and the spread of malicious malware via the Internet, a successful cyber attack could shut down multiple server farms at once, resulting in double contingency events where systems, like the IP telephony system, could be taken out of service for days, or even weeks. Additionally, while the probability of two major *physical* disasters (*e.g.*, fire, flood, wind damage) occurring at the same time at two different Company-owned server farms is very low, the potential for a natural disaster event combined with a successful cyber attack increases the risk of a dual-contingency event. This combination of events could damage the network infrastructure such that restoration would require a weeks- or months-long process of rebuilding and/or physical replacement of server and storage hardware and software. In either case, the Company would be unable to respond to electric, gas, and steam emergencies over the phone, or process phone or e-mail-based account transactions, for an unacceptable length of time.

In light of the growing threat of cyber security attacks, the Company has identified the IP telephony system's current single contingency configuration as an enterprise risk that requires additional investments to address the increasing likelihood of double contingency events. The Customer Experience Center Disaster Recovery program will help to mitigate this risk with a robust technology solution that will be implemented by the end of Rate Year 1.

Supplemental Information:

- Alternatives:
  The Company could continue to operate the IP telephony system utilizing the existing single contingency configuration and not implement additional hardening solutions to defend against double contingency events.

- Risk of No Action:
  If additional hardening solutions are not implemented to better defend and prepare against double contingency events, the Company runs the risk of experiencing a situation where the IP telephony system is forced offline, which would prevent customers from calling the Company to report outages, gas leaks, or other emergencies and/or conduct other business transactions via phone. In addition to requiring a costly restoration/rebuilding process for affected server farms (potentially involving both hardware and software), such an event would be a major disruption to Company operations and would also result in erosion of customer trust and increasing customer dissatisfaction.

- Non-Financial Benefits:
  This program will maintain reliable access to the Call Center and IVR self-service during double contingency events, providing seamless service availability to customers and, in the case of a system emergency event, an uninterrupted flow of critical outage and public safety-related information.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis:
  As mentioned above, in 2019 the Company will conduct a detailed assessment of possible solutions to mitigate the risk of an IP telephony system double contingency event. The Company will provide additional information on this assessment in its update testimony.

- Project Relationships (if applicable):
  The Customer Experience Center Disaster Recovery program solution will integrate with the new Customer Service System detailed in the Customer Energy Solutions panel.

- Basis for Estimate: The capital costs presented below were derived based on IVR development work performed in 2012 and 2013 and assumes a vendor-hosted disaster recovery solution will be implemented.

Total Funding Level ($000):

Capital - Historic Elements of Expense

(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P						
Other						
Total						

Capital - Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor					
M&S					
A/P		$1,500			
Other					
Overheads					
Total		**$1,500**			

X	Capital
	O&M

2019 – Customer Operations

Project/Program Title	Off-System Billing
Project Manager	Salvatore Flagiello
Hyperion Project Number	PR.21143171
Status of Project	Ongoing
Estimated Start Date	2013
Estimated Completion Date	December 2020
Work Plan Category	Strategic

Work Description:

Currently, the Company utilizes a number of off-system billing processes to perform complex billing, which occurs outside of the Customer Information System ("CIS"), the front-end mainframe application for the Customer Service System ("CSS"). These complex billing processes, which include new or modified rate structures and calculations, cannot be handled by CIS and instead are performed in the Company's Customer Care & Billing ("CC&B") application to automate certain rates and programs.

The Company continues to automate billing processes that support programs developed under Reforming the Energy Vision ("REV") proceeding. Some of the efforts completed in CC&B over the course of 2017-2018 include Standby Offset billing automation, Standby Reliability credit calculations, Distributed Generation Gas Load Factor Validation, Standby Multi-Party Offset billing and Standby Rate Pilot (Rider Q) billing. In addition, in March 2017, the Public Service Commission ("Commission") issued its *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters*[1] , which among other things, established the value of distributed energy resources ("VDER") value stack paradigm for compensating distributed generation sources. This compensation is detailed in the Company's VDER tariffs. As part of implementation of VDER, the Company made upgrades to CC&B and automated the calculation of value stack credits as well as the application of value stack credits to customer bills.

The Commission further indicated that it would make additional changes to the VDER program, among other rate designs, including expanding VDER eligibility and addressing rate design issues, in its *Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters*.[2] In the Phase One Order, the Commission indicated that it had only taken the "first steps in the necessary evolution of

[1] Case 15-E-0751, et.al., *In the Matter of the Value of Distributed Energy Resources* (VDER Proceeding), Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017).
[2] VDER Proceeding, Order on Net Metering Transition, Phase One of Value of Distributed Enegy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters (VDER Phase One Order) (issued September 14, 2017).

compensation for Distributed Energy Resources ("DER")," [3] and that "[f]urther evolution will occur through the Phase Two processes, including increased inclusion of storage and currently non-eligible technologies, refinements in the calculation of values like the Demand Reduction Value ("DRV") and Locational System Relief Value ("LSRV"), and rate design reforms to better reflect system costs and values in both credits for generation and charges for consumption." [4] The Commission later expanded the VDER program with its *Order on Value Stack Eligibility Expansion and Other Matters* on September 12, 2018. [5] As directed, the Company implemented the expansion of the value stack eligibility and availability of interzonal crediting, which became effective December 1, 2018. In the VDER Expansion Order, the Commission also recommended that Staff work with the New York State Energy Research and Development Authority ("NYSERDA") to further consider combined heat and power ("CHP") and find an appropriate VDER eligibility model, [6] and stated that Staff will continue to monitor community distributed generation ("CDG") projects so that the CDG program truly benefits customers and supports the achievement of New York's policy goals. [7]

The Company anticipates that the Commission will continue to approve new programs and rate designs under REV and other clean energy proceedings in conjunction with broader deployment of Advanced Metering Infrastructure ("AMI"). As such, the Company proposes to make a $1 million capital investment in Rate Year 1 to implement additional modifications and upgrades to its off-system billing processes to accommodate these changes. While the specific upgrades have not yet been defined because they are dependent upon future Commission orders, the requested amount will allow the Company to continue working toward meeting future customer billing needs and preparing for new and/or modified rates and special programs.

Justification Summary:

The Company must comply with all billing requirements that stem from the Commission's continued efforts to refine complex rate designs and the adoption and expansion of clean energy programs that rely on new billing approaches. Continued investment in off-system billing processes is imperative for the Company to deliver timely, accurate bills to customers participating in innovative new rates and programs.

By investing in billing automation in the CC&B application, the Company has been able to remain flexible and adapt to the billing paradigms stemming from the State's ambitious clean energy efforts. For example, since the Company's last rate filing, the Commission has approved additional complex rates and programs, such as the Rider Q and the value stack compensation model. The Company's implementation of the billing requirements associated with these programs were made possible by off-system billing investments.

Continued investment in off-system billing automation will allow the Company to respond efficiently and effectively to anticipated new requirements in the 2020-2022 time period. As noted above, the Commission has clearly expressed its intention to continue refining existing complex rates while also exploring new innovative rate designs. Relying on a manual billing

[3] *Id*, p. 2.
[4] *Id*, p. 53.
[5] VDER Proceeding, Order on Value Stack Eligibility Expansion and Other Matters ("VDER Expansion Order") (issued September 12, 2018).
[6] *Id*, p. 12.
[7] *Id*, p. 19.

process for these complex rates would diminish the experience of participating customers by increasing the risk of billing errors and delays in application of bill credits and/or charges. Furthermore, in the case of VDER tariffs and most other complex rates, the Company has already implemented automation in its CC&B application for billing purposes, so it follows that any further adjustment to the rates or tariffs will require additional CC&B programming. Also, while the Company seeks to invest in a CSS as discussed in the Customer Energy Solution Panel testimony, continued investment in off-system billing upgrades will not result in any stranded costs because the existing CC&B system will be seamlessly integrated with the new CSS, allowing for a smooth transition for customers billed under complex rates and programs.

In summary, continued investment in upgrading off-system billing processes not only facilitates the delivery of prompt and accurate bills to customers, but also supports New York's clean energy goals. Delaying investments to update systems and automate processes will not only lead to poor customer experiences as a result of late or incorrect bills, but also stifle customer adoption of REV programs because of poor customer experiences. The ability to develop and quickly automate processes as a result of new rates and programs will be imperative to engaging customers and ramping up participation in new REV programs.

Supplemental Information:

- Alternatives:
  - Use of manual processes to bill customers, which are difficult to support as customer participation grows and also increase the risk of billing errors and delays.

- Risk of No Action:
  - Taking no further action to automate future complex billing requirements would mean reverting to manual billing in order to accommodate future changes and additions. Increased use of manual processes would increase the costs associated with human resources required to perform these manual tasks and manage the necessary maintenance costs.
  - Manual processes jeopardize the accuracy of bill generation and revenue collection.

- Non-financial Benefits:
  - Continued investment in off-system billing processes reduces the risk of inaccurate and delayed billing associated with manual bill processes, thereby positively affecting the experience of customers participating in innovative rate designs and clean energy programs.
  - Automated billing platforms increase operational efficiency through quality control mechanisms, in addition to avoided human resource costs.
  - Improved database management and account maintenance.

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: For each new rate or program being automated, a fit gap analysis will be performed to determine the most efficient and cost-effective approach.

  Project Relationships (if applicable): The Company's continued investment in off-system billing automation is related to the new CSS program detailed in the Customer Energy

Solutions testimony. The New CSS will utilize the CC&B platform, which will allow for a seamless integration between the existing CC&B used by the Company for off-system billing processes and the New CSS. Continued investment in off-system billing processes is also related to the AMI program and the new Meter Data Management System ("MDMS") built to manage smart meter data. Additionally, as part of the Smart Home Rate – a REV demonstration project that offers residential customers granular energy price signals to encourage energy management and DER adoption – the Company built connections between the AMI MDMS and the existing CC&B system, which may be further utilized with any new rates or programs.

- Basis for Estimate: The proposed costs are estimated based on the Company's prior investments in automation of off-system billing processes.

Total Funding Level ($000):

Capital - Historical Elements of Expense
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor	$382	$284	$116	$124		$149
M&S						$22
A/P	$915	$390	$774	$654		$682
Other	$262	$247	$88	$80		$90
Overheads						
Total	**$1,559**	**$921**	**$978**	**$858**		**$943**

Capital - Future Elements of Expense

EOE	Budget 2019	Request 2020	Request 2021	Request 2022	Request 2023
Labor	$286	$311			
M&S					
A/P	$523	$548			
Other					
Overheads	$116	$141			
Total	**$925**	**$1,000**			

	Capital
X	O&M

2019 – Customer Operations

Project/Program Title	Revenue Protection Analytics
Project Manager	Richard Luong
Hyperion Project Number	N/A
Status of Project	Initiation
Estimated Start Date	1/2020
Estimated Completion Date	Ongoing
Work Plan Category	Operationally Required

Work Description:

The Revenue Protection Analytics program is one of Con Edison's operational priorities, as explained in the Customer Operations Panel testimony. The O&M requested in this white paper is related to the Company's ongoing use of the revenue protection software module associated with C3 IoT, which will be implemented in 2019. (Note: C3IoT is the technology platform utilized by the Company's Enterprise Data Analytics Platform ("EDAP"), which is designed to store and analyze smart meter data collected by the Company's Advanced Metering Infrastructure ("AMI").

The C3 IoT revenue protection software is designed to analyze data from prior instances of theft and other irregular metering conditions (*e.g.*, meter type does not correspond with what is in Customer Information System, broken meter, etc.), as well as incorporate external data, such as weather data, to identify and flag accounts that have similar consumption patterns. Accounts are then prioritized for investigation based on likelihood of theft or other irregular metering conditions. With the continued deployment of AMI, additional data will be incorporated, such as events and alarms that may serve as indicators of theft or other irregular metering conditions requiring investigation. The C3 IoT module also incorporates machine learning, a method of data analysis that automates analytical model building, to further refine the prioritizations based on success and failure of investigations on an ongoing basis.

Use of this software will enable the Revenue Protection Unit ("RPU") of Field Operations to systematically generate and prioritize leads for potential instances of theft or other irregular metering conditions. By leveraging the C3 IoT software and data described above, the Company will improve the success rate of RPU investigations and generate leads with higher potential for successful revenue recovery.

The operations and maintenance ("O&M") costs associated with use of the C3 IoT revenue protection software module include annual maintenance, support, and hosting fees. The Company also requires O&M funding to hire and maintain two Senior Specialists in Field Operations that will analyze data, work with field forces to verify and report on investigation findings, and work with the software vendor to refine the machine learning models as needed.

Justification Summary:

RPU is responsible for investigating possible instances of energy theft from the Company and working with billing operations to back charge customers for instances of theft and other irregular metering conditions. Successful RPU investigations benefit all customers by recovering lost revenue – the cost of which would otherwise be socialized – and also by uncovering unsafe metering conditions that pose a threat to public safety.

One of the primary – and most successful – sources of leads for RPU investigations comes from the Company's Customer Field Representatives ("CFRs"). Due to the AMI deployment, however, the Company plans to decrease the number of CFRs employed as outlined in the AMI Business Plan[a]. As a result of this decrease in CFRs, fewer investigation leads will be generated, and the potential for an increase in unchecked theft or irregular metering activity will rise.

To adapt to these new operating conditions while maintaining the same or better performance, RPU must find investigation leads from other sources, including utilizing new data and information available from the AMI implementation. With an end state of approximately 5 million AMI meters / end points, and 450 possible events / alarms per meter communicated in 15 or 5 minute intervals, the Company is greatly expanding its visibility into meter functionality and benefitting from new indicators and alarms, including tampered meters. However, converting this data from the AMI systems (Head End System ("HES") and/or Meter Data Management System) into actionable leads requires the type of advanced data analytics offered by the C3 IoT revenue protection software module.

Adequate and operationally efficient revenue protection requires a new analytics-based approach to identifying and prioritizing accounts for RPU investigation. The O&M funding requested for this program will enable RPU to use the C3 IoT revenue protection software and implement necessary software updates/maintenance.

Supplemental Information:

- Alternatives: As noted above, the Company is implementing the C3 IoT revenue protection software module in 2019. In order to effectively leverage this new tool for RPU operations the Company requires O&M funding for two FTEs to use the software, and the cost of licensing the software. If the Company elected not to incur these O&M costs, it would not be able to utilize the software module beginning one year after its implementation.

- Risk of No Action: The risk of not taking action is the same as the risks described in the 'Alternatives' section above.

- Non-financial Benefits: Effective use of the C3 IoT revenue protection software module will require ongoing collaboration between the Company's AMI, Information

[a] Case 15-E-0050, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service ("2015 Rate Case")(filed November 16, 2015).

Technology, and RPU subject matter experts. This collaboration will facilitate shared knowledge as the teams work together to apply the information available from the AMI platforms and refine the revenue protection analytics over time using machine learning. Use of this software will also require tying together multiple data sources, which may lead to other opportunities to leverage these data sources that are currently not known.

- Summary of Financial Benefits (if applicable) and Costs: Based on projections provided by the Company's C3 IoT vendor, leads generated from the new revenue protection software module are projected to result in a 25 percent increase in its success (true positive) rate, and twice as much recovery per true positive, within a one-year ramp up, resulting in a potential incremental increase in back billing by up to $30 million annually after the first year.

- Technical Evaluation/Analysis: The Company considered multiple revenue protection software modules prior to selecting the C3 IoT module for implementation in 2019. However, the only viable alternative module would have required higher post-implementation spending and did not come with the benefit of machine learning capabilities.

- Project Relationships (if applicable): This program leverages the C3 IoT platform, which is the technology utilized by the Company's EDAP, and is therefore contingent upon the Company's successful implementation, utilization and maintenance of EDAP.

  The effectiveness of this program will also depend on the quality of data drawn from the AMI HES, which is contingent upon the completed rollout of the AMI project, as outlined in the AMI Business Plan.

- Basis for Estimate: The basis of this estimate is from vendor quotes and projected time and effort required of human resources.

Total Funding Level ($000):

O&M - Historical Elements of Expense
(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P						
Other						
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

O&M - Future Elements of Expense

EOE	**Budget 2019**	**Request 2020**	**Request 2021**	**Request 2022**	**Request 2023**
Labor		$201	$201	$201	$201
M&S					
A/P			$308	$308	$308
Other					
Overheads					
Total		**201**	**$509**	**$509**	**$509**

Revenue Protection Analytics Worksheet
(‘000s)

O&M	O&M Change 2020 (RY1)	O&M Change 2021 (RY2)	O&M Change 2022 (RY3)
Labor – Customer Operations	$201	$0	$0
Software Maintenance Fees	$0	$308	$0
Total	$201	$308	$0

	Capital
X	O&M

2019 – Customer Operations

Project/Program Title	Customer Outreach and Education
Project Manager	Hollis Krieger
Hyperion Project Number	N/A
Status of Project	In progress
Estimated Start Date	In progress
Estimated Completion Date	Ongoing
Work Plan Category	Strategic

Work Description:

The Company's Customer Outreach program was developed to provide outreach and education activities and programs and materials to educate the Company's customers regarding their rights, responsibilities and options as utility customers. Increased funding for this program is needed for the following activities:

- Development of additional personalized online (website), offline (email), and mobile (mobile app) engagement campaigns that provide customer specific and actionable information to targeted audiences;
- Expansion of email campaigns including those associated with key customer journeys;
- Research to gain customer insights on new outreach and education campaigns and resources;
- Expanded training for Company employees in enhancing the customer experience ("CX") and other topics including Reforming the Energy Vision ("REV") initiatives and diversity and inclusion competency; and
- Increased costs for postage and materials involved in direct mail campaigns and educational awareness materials.

Justification Summary:

Sustained messaging is needed in order to increase customer understanding and awareness of energy safety and the various Company resources and programs that are available to customers. The Company provides this information through the Customer News bill insert, online at coned.com, through email blasts, informational brochures, and via media messaging. It is important that this information is continually refreshed to remain current and useful to customers. In addition, our customer research reflects that customers are most engaged by communications that are personalized and provide actionable information. Providing this type of communications requires development of personalized campaigns that provide customized and actionable information to targeted audiences.

To meet our commitment to enhancing the customer experience and meeting the rising expectations of customers, it is important that we provide customers with information of importance to them that is easy to understand and delivered in their preferred channel. The quality of our employees and contractors interactions with our customers is also critical to our success in providing industry-leading CX, as is customer research aimed at understanding the outreach and education resources that are most preferred and accessible to our customers.

Supplemental Information:

- Alternatives: Reduce the level and quality of outreach and education provided to our customers and reduce CX training to our employees and contractors. This is not preferred as it would limit the Company's ability to inform and engage our customers and impair CX focus.

- Risk of No Action: The Company's ability to refresh and enhance outreach and educational resources and develop resources for new initiatives will be limited. Employee engagement and focus on CX will be reduced.

- Non-Financial Benefits:
  - Increased customer understanding and awareness of energy safety and Company resources and programs that are available to them.
  - Improved customer satisfaction

- Summary of Financial Benefits (if applicable) and Costs: N/A

- Technical Evaluation/Analysis: N/A

- Project Relationships (if applicable):
  - Public safety awareness initiatives of Gas Operations
  - REV initiatives
  - Digital Customer Experience

- Basis for Estimate: The estimate is based on costs experienced for these programs.

Total Funding Level ($000):

O&M - Historical Elements of Expense

(Historical EOE breakout will only be completed for Steam projects/programs of $500 thousand or more and, for all other organizations, projects/programs of $1million or more.)

EOE	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Historic Year (O&M only)	Forecast 2018
Labor						
M&S						
A/P		$2,551	$3,329	$3,238	$2,790	$2,667
Other						
Total		**$2,551**	**$3,329**	**$3,238**	**$2,790**	**$2,667**

O&M - Request by Elements of Expense

EOE	**Budget 2019**	**Request 2020**	**Request 2021**	**Request 2022**	**Request 2023**
Labor					
M&S					
A/P	$2,980	$3,456	$3,559	$3,666	$3,776
Other					
Overheads					
Total	**$2,980**	**$3,456**	**$3,559**	**$3,666**	**$3,776**

Outreach & Education Worksheet
($000s)

		Actual 2018	Forecast RYE 2019	Forecast RYE 2020	Forecast RYE 2021	Forecast RYE 2022	Variations
Employee Education	Web-based "eLearning" modules centered on *Enhancing the Customer Experience* and other important topics; educational videos; employee-engagement campaigns.	$39	$70	$170	$135	$170	2020 - 2022 - Increased costs for training in customer experience and other topics (e.g., D&I, REV).
Customer Outreach Events	Participation in 85+ energy-themed and community events per year; collateral for distribution at events; association dues for community advocacy groups.	$300	$263	$300	$300	$318	2020 - 2022 - Increased costs are projected for collateral.
Education and Awareness Literature and Publications	Bill inserts, including Customer News — the Company's multi-topic newsletter, which is sent quarterly to all customers; Spotlight — the Company's biannual newsletter for elderly, blind and disabled customers; brochures, flyers and other printed material for distribution at Company events and upon customer request.	$456	$443	$500	$500	$518	2020 - 2022 - Increased costs are projected for printing and postage costs.
Website Improvements	conEd.com/kids upgrades and maintenance; maintenance and enhancement of the *My Energy Calculators* suite of online bill analysis tools; continued support of the mobile-optimized version of conEd.com and the My conEdison mobile app; *Customer Central* website enhancements.	$24	$0	$0	$0	$0	2020 - 2022 - Cost eliminated due to migration of energy calculators to DCX platform.
Direct Mail	Direct mailings to life-support equipment (LSE) customers, community organizations, medical professionals and master-metered buildings with elevators; energy-safety mailings to direct and indirect Con Edison customers.	$393	$533	$446	$524	$460	2020 - 2022 - Fluctuation from year to year due to scratch and sniff mailing every other year to master metered buildings and some increases expected in postage and printing costs.
Educational Media Messaging	Annual energy education ad campaign; online videos on billing-and-payment-related topics; blast email campaigns (general education and storm-related); energy and safety program for schoolchildren; kids mobile applications.	$1,238	$1,315	$1,640	$1,640	$1,640	2020 -2022 -increased costs to expand energy management information and tools and increased email blast campaigns.
Market Research and Customer and Stakeholder Focus Groups	Focus groups; Company-sponsored customer opinion surveys; subscriptions to utility customer satisfaction studies.	$217	$356	$400	$460	$560	2020 - 2022 - Increased costs for research (surveys, focus groups) and subscriptions to studies.
Total		**$2,667**	**$2,980**	**$3,456**	**$3,559**	**$3,666**	

Low Income Program – Electric

Electric Low Income Discount Levels Used to Estimate 2017-2019 Discount Target Budget Amount ($54.7M)

Income Level	Electric Non-Heat	Electric Heating
Tier 1	$10	$10
Tier 2	$10	$10
Tier 3	$14	$22
Tier 4	$0	$0

Electric Low Income Participation Levels Used to Estimate 2017-2019 Discount Target Budget Amount ($54.7M)

	Electric Non Heat	Electric Heat
Total	**462,346**	**1,256**

Electric Low Income Discounts Used to Estimate 2020-2022 Discount Target Budget Amount ($52.8M)

Income Level	Electric Non-Heat	Electric Heating
Tier 1	$10	$10
Tier 2	$10	$10
Tier 3	$27	$27
Tier 4	$12	$12

Electric Low Income Participation Levels Used to Estimate 2020-2022 Discount Target Budget Amount ($52.8M)

	Electric Non Heat	Electric Heat
Tier 1	385,959	1,494
Tier 2	959	83
Tier 3	2,477	255
Tier 4	36,509	142
Total	**425,904**	**1,973**

Low Income Program – Gas

Gas Low Income Discount Levels Used to Estimate 2017-2019 Discount Target Budget Amount ($10.9M)

Income Level	Gas Non-Heat	Gas Heating
Tier 1	$3	$50
Tier 2	$3	$50
Tier 3	$3	$50
Tier 4	$0	$0

Gas Low Income Participation Levels Used to Estimate 2017-2019 Discount Target Budget Amount ($10.9M)

	Gas Non Heat	Gas Heat
Total	**107,910**	**17,470**

Gas Low Income Discounts Used to Estimate 2020-2022 Discount Target Budget Amount ($15.9M)

Income Level	Gas Non-Heat	Gas Heating
Tier 1	$3	$50
Tier 2	$3	$50
Tier 3	$3	$56
Tier 4	$3	$50

Gas Low Income Participation Levels Used to Estimate 2020-2022 Discount Target Budget Amount ($15.9M)

	Gas Non Heat	Gas Heat
Tier 1	97,071	14,519
Tier 2	9	965
Tier 3	43	2,633
Tier 4	15,301	1,380
Total	**112,425**	**19,498**