Long Island Power Authority

Repowering Feasibility Study
Northport Power Station

May 20, 2020

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OVERVIEW

Chapter 58 of the Laws of 2015 enacted Senate Bill 2008-B and Assembly Bill 3008-B (the Bill) and directed the Long Island Power Authority (LIPA or the Authority), in cooperation with, its service provider, PSEG Long Island (PSEG LI), and the owner, National Grid (National Grid, Grid or GENCO), of the legacy LILCO power generating stations, to perform, or direct the performance of, engineering, environmental permitting, and cost feasibility analyses and studies (Repowering Study or Study) for repowering the E. F. Barrett (Barrett), Port Jefferson, and Northport power stations using "greater efficiency and environmentally friendly technologies." The Barrett and Port Jefferson Studies were completed in April 2017**.** Upon completion of the Study, LIPA, if it were to find that repowering any of the noted generating facilities "…is in the best interests of its ratepayers and will enhance the [A]uthority's ability to provide a more efficient, reliable and economical supply of electric energy in its service territory…", would exercise its rights under the Power Supply Agreement (PSA)[1] related to repowering.

As required by the Bill, this Study evaluates repowering the Northport facility using more efficient and environmentally friendly technologies. It is not a broad assessment of all system-wide options available to LIPA. Accordingly, it is important to note that there are other potential options available to LIPA that might achieve the same or greater benefits, at a lower cost, as a Northport repowering. A full analysis of these options, however, falls outside the scope of this Study.

It is also important to recognize that LIPA's typical process regarding changes to the electric system is to identify a need/problem/opportunity, then competitively solicit alternatives that best address the issue(s) at the lowest cost to customers. This repowering Study reverses this process by evaluating specific solutions first, an approach that is not optimal for solving today's and future system needs.

Executive Summary

This report finds no compelling reason to repower the Northport power station to maintain its existing production capacity. Moreover, all the repowering options studied will increase customer costs. While repowering Northport is technically feasible, its benefits do not outweigh its considerable costs. Repowering Northport would result in

[1] Amended and Restated Power Supply Agreement dated October 12, 2012 between LIPA and National Grid. This Agreement pertains to Barrett, Port Jefferson, and Northport, among other units.

a substantial increase in costs to customers versus the status quo which, depending on the repowering Scenario evaluated, ranges from approximately $1.2 billion to $2.1 billion.[2]

The station has become increasingly uncompetitive in the energy market as manifested by a steady decline in its average capacity factor – from 55.8% in 2005 to 15.2% in 2019. The average capacity factor is forecast to further decline to 2.9% in 2035. Consequently, the most cost effective of the options studied is to retire a Northport steam unit, which would significantly reduce costs. Retirement - not a repowering – of just one of the four existing steam units results in savings to customers of approximately $303 million[3] over the period 2020 to 2040 without jeopardizing reliability standards.

Six different scenarios, five associated with repowering and one, as mentioned, examining the retirement of a single unit, were analyzed as part of the Study. None of the repowering scenarios studied are of economic benefit to customers. Bills to customers would increase above where they would otherwise be under the status quo (i.e., the Reference Case) for all of the repowering scenarios evaluated and would decrease with a unit retirement. This finding is not surprising given the outlook for Long Island and the State overall that shows: 1) a current surplus of installed generating capacity that is expected to grow as new, clean renewable resources are added in response to state policy and legislation and; 2) load growth that is expected to decline until 2028 and then increase only gradually thereafter.

The changing market and regulatory conditions will be evaluated in detail in LIPA's next Integrated Resource Plan (IRP), scheduled to begin in 2020. Results of the IRP will provide a roadmap for decisions regarding the deployment of new, clean energy on Long Island and the disposition of existing generation capacity.

LIPA has made no decision as yet regarding the retirement of additional steam plants (Northport, Barrett or Port Jefferson) beyond those at Far Rockaway and Glenwood that were retired in 2012. However, it is likely that results of analyses conducted during 2020 will indicate that additional closures, as early as 2022 – 2023, make economic sense. Consequently, the retirement of one or more of the steam units at Northport is more likely in the coming years than a repowering of the plant as long as the impacts on the reliability of power supply both for Long Island overall and for the local area served by the plant remain within acceptable criteria. Such a decision would be consistent with LIPA's more recent decision to retire two gas turbine units in 2020 and 2021.

[2] Total Net Present Value (NPV) costs through the study period 2020 - 2040 of a full repowering (i.e., retiring and replacing all, or most, of the existing steam unit's capacity) and assumed Power Purchase Agreement (PPA) type.

[3] Total NPV savings assumes a reduction of approximately 25% of current property taxes. However, even assuming no change in property tax levels, it is still economically beneficial to retire at least one Northport unit.

While additional renewable generation and energy storage are likely to be built on Long Island pursuant to the Climate Leadership and Community Protection Act (CLCPA), the optimal location for such resources will be determined through future system-wide studies and procurements. Accordingly, a decision now to install any new generation at Northport generating station is not in the best interests of LIPA's customers.

The remaining sections of this chapter provide summary descriptions of the existing plant, the potential for deployment of renewable technologies at Northport, the repowering scenarios evaluated, and the key findings of the Study.

The Existing Plant

The Northport Power Station is located on Waterside Ave in the town of Huntington along the north shore of Long Island in Suffolk County, NY. The parcel of property totals approximately 250 acres of which only approximately 75 acres is land usable for repowering. The steam units include four dual-fuel Combustion Engineering boilers with four General Electric (GE) turbine-generators, each unit of 375 MW nameplate capacity. Also on the site is a single 16 MW GE Frame 5 gas turbine, combining for a station total of 1,516 MW. The units at Northport are operated under the terms of the PSA and unit commissioning occurred on the following dates:

- Steam units 1, 2, 3, and 4 were commissioned in 1967, 1968, 1972, and 1977, respectively.
- The 16 MW GE Frame 5 gas turbine was commissioned in 1967.

Starting in 1993, the capability to burn natural gas was added to the steam units giving them the ability to burn either natural gas or fuel oil. Natural gas is delivered by pipeline extension of the Local Distribution Company (LDC), Keyspan Gas East dba National Grid. The steam units are once-through cooled with water from the plant's intake structure and discharge to Long Island Sound. The electrical point of interconnection is to an onsite LIPA substation.

The station is economically dispatched by the NYISO but has become increasingly less competitive in the energy market in recent years as manifested by a steady decline in the steam units' average capacity factor. In 2005, the steam units' average capacity factor was 55.8%, but only 15.2% in 2019. The station, though, is highly reliable as measured by its availability to operate, particularly during the critical summer months, June through August. In the summer periods from 2014 – 2019, the units were available to generate energy an average of over 96% of the time, significantly above a peer group average of about 88%.

While the operation of the existing Northport steam units shows a steady and likely inexorable decline in capacity factor, its high level of availability, particularly for a plant with units commissioned in the 1960's and 1970s, reflects National Grid's sound and well-executed capital investment program and operations and maintenance philosophy. And while it is not possible to predict how the units will operate in the future, given past performance, current operation and maintenance practices, and reasonable expected levels of capital investment, the Study assumed, as part of the Reference Case analysis, that Northport could continue to operate reliably through 2040 when it would be shut down consistent with New York State's recently enacted CLCPA mandate for 100% carbon free electricity generation.[4]

Plant Ownership and Offtake Agreement

The Northport power station is owned by National Grid. LIPA is entitled to all of the power output of the plant under the terms of the Power Supply Agreement between Grid and LIPA, and has certain rights to approve and request investment projects, including repowering, and to retire units, with LIPA bearing the cost responsibility per the terms of the PSA. The contract expires April 30, 2028, at which point entitlement to the power output of the station reverts to National Grid. In the case of repowering, this study assumed that LIPA would enter into a long-term Power Purchase Agreement (separate from the PSA) for the power output of each of the repowered units.

Technology Evaluation

Given the relatively limited acreage available at Northport for development of renewable resources, the Northport repowering Study typically would not have examined the possibility of large-scale renewable development at the site. However, in recognition of CLCPA mandates, which effectively eliminate the use of all non-renewable energy resources by 2040, an examination of the renewable energy potential at Northport was undertaken. A total of ten (10) renewable technologies were examined, including:

- Solar Photovoltaic
- Solar Thermal
- Onshore Wind
- Hydroelectric
- Geothermal

[4] The CLCPA created numerous other mandates, among them that that 9,000 MW of offshore wind will be in developed by 2035 and that there will be 3,000 MW of energy storage in the state by 2030.

- Tidal
- Wave
- Ocean Thermal
- Fuel Cells
- Offshore Wind

As described in Chapter 4, no renewable technology was deemed practical (exclusive of interconnecting offshore wind at Northport) or remotely sufficient in terms of potential development size to replace Northport's current capacity largely due to the restrictive site size and/or lack of appropriate natural conditions at the site. This conclusion led to the need to develop repowering scenarios that included conventional generation.

Repowering Scenarios

The Study assessed the impacts of Grid's base proposal (Scenario 3) to repower Northport plus five (5) other scenarios. These six scenarios were then evaluated against a Reference Case. The six scenarios and the associated technology configuration of each are depicted below in Table ES-1. Scenario 3 represents Grid's proposal. The five other scenarios were:

- One (1) scenario that retires one Northport steam unit (375 MW), i.e., Scenario 6.
- One (1) scenario that represents a repowering of a single unit, i.e., Scenario 1.
- One (1) scenario that represents close to a full repowering of existing capacity, i.e., Scenario 5.
- Two (2) scenarios that represent a full repowering of existing capacity, i.e., Scenario 2 & 4.

The Reference Case includes all existing and planned generating units with the exception of two small existing combustion turbines at other LILCO-era stations that have been announced for retirement. The economic analyses described in this report compare the annual revenue requirements for the Reference Case versus each of the six scenarios.

All scenarios use the same load forecast, projected fuel and emissions prices, and the same set of existing and planned generating resources aside from the retirements and/or additions specific to the scenario. The multiple scenario approach was adopted to provide a more robust range of potential solutions for a repowered Northport given the rapidly changing technology, market, and regulatory environments. Since no renewable technology, exclusive of interconnecting offshore wind at Northport was deemed practical (feasibility has not been determined), all replacement capacity was assumed to be either conventional gas-fired generation or batter energy storage systems (BESS or batteries).

Table O-1: Repowering Scenarios: Capacity Retirements/ Additions

Unit Type/Status	Unit Size	Scenario					
		1	2	3	4	5	6
NP Units to be Retired	NP 1 (375 MW)	Y	Y	Y	Y	Y	Y
	NP 2 (375 MW)	---	Y	Y	Y	Y	---
	NP 3 (375 MW)	---	Y	Y	Y	Y	---
	NP 4 (375 MW)	---	Y	Y	Y	Y	---
Net Existing Capacity		**1,125 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**1,125 MW**
New CC	**340 MW**	1 ea.	2 ea.	2 ea.	1 ea.	2 ea.	---
New SC	**230 MW**	---	4 ea.	3 ea.	3 ea.	2 ea.	---
New BESS	**50 MW**	1 ea.	---	3 ea.	3 ea.	3 ea.	---
New OSW	**800 MW***	---	---	---	1 ea.	---	---
NNC Cable Upgrade	**229 MW**	---	---	---	---	1 ea.	---
Added New Capacity		**390 MW**	**1,600 MW**	**1,520 MW**	**1,580 MW****	**1,290 MW*****	**0 MW**
New Northport Plant Capacity		**1,515 MW**	**1,600 MW**	**1,520 MW**	**1,580 MW****	**1,290 MW*****	**1,125 MW**
COD Range of New Capacity		2025 - 2026	2026 - 2032	2025-2034	2025 - 2034	2025 - 2034	---

* Nameplate capacity; UCAP capacity is assumed to be ~400 MW
** Assumed UCAP capacity for offshore wind
*** NNC cable upgrade does not count as UCAP capacity

Note that for each Scenario the units to be retired are indicated by a "Y" in the table. (The absence of a "Y" indicates that the unit is not retired.) The "Net Existing Capacity" row is the total capacity associated with the existing units post retirement(s). "Added New Capacity" represents the total new capacity added in each Scenario and is determined by summing the amount of capacity associated with the specific type and amount of new capacity in a Scenario. "New Northport Plant Capacity" is the sum of the "Added New Capacity" and "Net Existing Capacity."

Repowering an existing power plant is in some respects more complicated and time consuming than ground-up construction on a vacant property. The analysis indicates that the range of time for implementation of the complete complement of technologies for 4 of the 6 scenarios is between 12 and 14 years (starting from 2020). This extended period is largely due to limited site acreage and the consequent required staging of permitting and construction of the replacement capacity, and the demolition activities associated with the existing capacity. The extended period also has a significant impact on the time available (it is reduced) for Grid to recover project costs under the assumption that natural gas fired generation cannot be part of the State's resource supply mix from 2040 onwards per the CLCPA. The shortened period to recover costs associated with conventional generation translates to increased costs when compared to recovering costs over a time period that extends beyond 2040.

As indicated, Grid developed and provided pricing proposals for new combined cycle units, simple cycle units, and batteries (i.e., Scenario 3). Those pricing proposals formed the basis for financial analysis of the other scenarios. Grid's pricing included, among other things, fixed annual capacity payments, fixed O&M payments escalated annually, and variable operations and maintenance charges. Provision of fuel would be the responsibility of LIPA. The financial analysis of the Northport repowering options was based on a model used for LIPA's financial projections. It was assumed that the repowered plant's annual taxes would remain the same as that incurred on the existing plant.[5]

Considering the CLCPA's goals – 100% carbon free electricity production by 2040 – in general, current resource planning activities aim to eliminate the use of conventional generation fired by fossil fuels by 2040.[6] This introduced a complication into the Study. Given that there is a restriction by 2040 on the use of carbon-based fuels, it raises a question about what contract term should be assumed for a project that is part of a repowering. To deal with this issue (i.e., contract term), the Study analyzed the effects of contracts for non-renewable resources that expired by 2040 with full recovery of project costs by that time, and standard 20-year contracts for non-conventional technologies that would expire post 2040, which allows for cost recovery over the entire 20-year contract term.

[5] Scenario 6, retirement of a single Northport steam unit, did assume an annual reduction in taxes of approximately 25 percent.

[6] It does not eliminate, however, conventional generation fired by a renewable fuel, such as hydrogen or a liquid fuel derived from biomass.

Findings

The key findings of the results of the Northport repowering Study are presented in conformance with the requirements of the Bill. They are as follows:

- A repowering of the Northport power station using only renewable technologies to replace the plant's existing capacity is not feasible from a technical perspective due to restrictive site acreage and/or lack of favorable natural conditions at or in the vicinity of the site.
- A repowering of the Northport power station using conventional technology (i.e., natural gas-fired generation) as part of a repowering configuration is feasible from a technical and environmental permitting perspective but is not economic (i.e., it increases costs to ratepayers).
- The total aggregate cost impact of a complete, or near complete, repowering (Scenarios 2 - 5), or partial repowering (Scenario 1) is significant and varies by assumed PPA length. The table below provides a summary of the incremental increase (or decrease in the case of a single unit shutdown – Scenario 6) in total costs and in the total bill impact for a typical residential customer under each scenario when compared to the Reference Case.

Table O-2: Increased Costs thru the Study Period (2020 - 2040)

Total Incremental Costs (NPV: $millions)						
	Scenario					
PPA Type	1	2	3	4	5	6**
20-Year	$682	$1,704	**$1,616**	$1,220	$1,569	($303)
Full Recovery by 2040*	$770	$1,982	**$2,081**	$1,470	$1,948	($303)

Total Incremental Residential Bill Costs ($)						
	Scenario					
PPA Type	1	2	3	4	5	6**
20-Year	$597	$1,565	**$1,480**	$1,092	$1,436	($263)

Full Recovery by 2040*	$663	$1,794	**$1,894**	$1,301	$1,768	($263)

* Only for technologies using fossil fuel.
** Unit 1 retirement only. There is no associated PPA with Scenario 6. Results are based upon a reduction of approximately 25% in Northport property taxes

- Retirement of a single unit at Northport (Scenario 6) results in an incremental decrease in the net present value of total costs as well as a total bill reduction for a typical residential customer.
- Retiring a single steam unit and replacing it with new conventional combined cycle technology (Scenario 1) increases total costs in the range of $0.7 to $0.8 billion.
- The net present value of the incremental total cost increase over the Study Period associated with a complete or near complete repowering of Northport (Scenarios 2 – 5) ranges from approximately $1.2 billion to $2.1 billion depending on replacement technology type.
- The total incremental bill impact for a typical residential customer over the Study Period associated with a complete or near complete repowering of Northport (Scenarios 2 – 5) ranges from approximately $1,100 to $1,900 depending on replacement technology type.

- The existing Northport steam units have shown a relatively steady drop in average capacity factor, declining from a high of 55.8% in 2005 to a six-year average (2014 – 2019) of 18.2%.[7] Seasonal variations include higher summer-month operations (recent capacity factors of approximately 30%) and peak winter-month operations when ambient temperatures are low. During spring and fall months, capacity factors are very low. The utilization of the steam units is expected to continue to decline as increased amounts of renewable resources are added to the system.

- An independent plant condition assessment indicated that the existing Northport units are well maintained, reliable for their age, and with reasonable projected capital and operations and maintenance expenditures can maintain their reliability for the foreseeable future.[8] The condition

[7] A capacity factor of 100% means that a plant would be operating at its full capacity every hour of the year.
[8] "Condition Assessment of National Grid Electric Generation Assets, Technical Report," and "Projections of Capital and O&M Expenditures for National Grid Electric Generation Assets"; RCM Technologies, Inc., December 30, 2014.

assessment results are consistent with recent operating performance. Overall, Northport's operating performance compares favorably to similar units in operation during recent years (2014 – 2019).

- Repowering conventional units typically makes the most sense where the fixed and variable costs of continuing to operate the older units is high compared to the costs for new technology. Major drivers usually include the relatively high cost of fuel for inefficient older units and the associated relatively high fixed costs of new technology. However, under current conditions where projected gas prices are quite low by historic measures and considering the low expected capacity factors for the steam units over the study period, fuel cost savings of new units, and their high fixed costs, do not provide a compelling reason to pursue Northport repowering using conventional technologies. Whether Northport could be a good site for installation of energy storage or interconnection of offshore wind is a question that remains to be answered by competitive procurements to occur in 2020 and beyond, as well as through further studies.

- Significant uncertainty exists around the size, timing, type, and location of new renewable generation to be built on or around Long Island pursuant to the CLCPA. Also, energy efficiency and the growth in distributed energy resources, such as rooftop solar, have significantly reduced LIPA's forecasted need for new generation. For example, the preliminary 2020 peak-load forecast for 2030 is over 2,500 MW less than the forecast for 2030 prepared in 2013, resulting in a peak load forecast reduction of over one and one-half times the size of the proposed Northport repowering.

- The current size of the generation portfolio on Long Island is greater than current needs and is projected to remain so for the foreseeable future. This excess provides significant redundancy and flexibility to meet changing but currently uncertain needs. New, long term commitments to generation now would reduce the flexibility to respond to changing conditions.

- The Study assumed property taxes associated with the repowering scenarios would remain at the same level as the status quo,[9] which currently are multiple times the level paid on a per megawatt-hour basis for another combined cycle plant (Caithness) installed on Long Island.

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[9] Scenario 6, retirement of a single Northport steam unit, did assume an annual reduction in taxes of approximately 25 percent.

1. SCOPE, OBJECTIVES & APPROACH

Chapter 58 of the Laws of 2015 enacted Senate Bill 2008-B and Assembly Bill 3008-B (the Bill) directing the Long Island Power Authority (LIPA or Authority), in cooperation with, its service provider, PSEG Long Island (PSEG LI), and the owner, National Grid (National Grid, Grid or GENCO) of the legacy LILCO power generating stations, to perform an engineering, environmental permitting and cost feasibility analysis and study (Repowering Study or Study) of repowering the Northport Power Station (Northport). Further, the Bill required LIPA to study repowering utilizing greater efficiency and environmentally friendly technologies.

1.1 SCOPE & OBJECTIVE

The scope of the Study was to perform an engineering, environmental permitting, and cost feasibility analysis of the potential repowering of Northport. The Study includes the system-wide energy and capacity impacts that result from such a repowering and makes assumptions regarding important local issues such as property taxes. Importantly, while the analysis included the impacts of exogenous factors, such as compliance with the State's goal of 70 percent renewable energy by 2030 (i.e., 70 x 30), it does not fully reflect the State's goal of 100 percent carbon free electricity production by 2040 (i.e., 100 x 40).[10] The 2040 goal was not modeled due to the significant uncertainty surrounding numerous other impactful factors, such as the load forecast, under a 100 x 40 scenario. Nevertheless, the results are considered conservative (i.e., more economically favorable) regarding a repowering of Northport because meeting the 100 x 40 goal would introduce additional, low marginal cost renewables into the system, thereby making a repowered Northport less economically attractive.

As required by the Bill, this Study exclusively evaluated repowering the Northport facility using more efficient and environmentally friendly technologies. It was not a broad assessment of all system-wide options available to LIPA, some of which might produce environmental and efficiency effects similar to or perhaps greater than those achieved by repowering Northport, but at a lower cost. For example, in lieu of repowering Northport, an alternate investment to build a new renewable energy facility, such as offshore wind, or a new simple or combined cycle facility at a different location, or simply retiring Northport and upgrading the proximate transmission system infrastructure (thereby eliminating all local power plant emissions), may be more cost effective and environmentally friendly than repowering Northport. Accordingly, it is important to note that there are other potential options available to LIPA that might achieve the same or greater benefits at a lower cost than a Northport repowering. However, a full analysis of these options falls outside the scope of the Study.

[10] The Reference Case results in approximately 91% emissions free electricity production statewide by 2040.

The objective of the Study was to provide the LIPA Board of Trustees with the necessary background and analyses regarding the potential repowering of Northport. As stated in the Bill, the Study is intended to support LIPA in determining if repowering "…is in the best interests of its ratepayers and will enhance LIPA's ability to provide a more efficient, reliable, and economical supply of electric energy in its service territory..." It should be noted that while this report is not intended to represent final repowering design or cost parameters, the results reflect realistic representations of potential plant design and cost characteristics.

1.2 APPROACH

The Study is structured to address the following questions in the context of its objectives:

- Is repowering Northport technically feasible, environmentally friendly, and economically viable?
- Is now the optimum time for deciding when and how to repower Northport, if it is deemed beneficial?

The Study developed the following framework to address the questions and uncertainties associated with repowering:

- Define a Reference Case against which potential repowering scenarios could be evaluated.
- Define the repowering scenarios to be considered.
- Provide the background and information required to assess the repowering scenarios.
- Assess repowering engineering characteristics and issues, such as:
    - What facility changes would result from repowering?
    - What are the repowered plant performance characteristics?
    - What changes are required to fuel the repowered plant?
    - What changes are required to connect the repowered plant to the electric grid, and assess the ability to export and transmit power on the grid?
- Identify and address the environmental considerations for the repowered facility, such as
    - The permits required to build and operate the repowered facility.
    - The studies required to obtain the necessary permits.
- Identify and assess miscellaneous project implementation issues, such as:
    - Constructability considerations.
- Assess the economic viability of the repowering project, considering such items as:
    - Electric load forecasts and expected plant dispatch characteristics.
    - PSA ramp down and repowering provisions.

    - Financial cost to LIPA's customers.
- Assess the impact on the community of a repowering project

In addition to the analyses, assessments and considerations above, the Study also considered the changing environment in which the decision to repower Northport would be made. These conditions, such as the recently enacted CLCPA, ongoing New York State energy initiatives, and evolving environmental policies and regulations, result in significant uncertainty as to future electric grid needs. Accordingly, the Study considered the time frames for when current uncertainties might be clarified versus the expected remaining life (i.e., ongoing reliable operation) of the current power plant.

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2. BACKGROUND & INPUTS

Under the Amended & Restated Power Supply Agreement (PSA) between LIPA and Grid, LIPA purchases capacity and energy from Grid from a fleet of steam and combustion turbine generating units aggregating approximately 3,700 MW. Within this fleet are eight steam generating units located at three sites totaling approximately 2,350 megawatts. Those three sites are the Northport, Port Jefferson and Barrett power stations. Grid also owns and operates 41 combustion turbine generating units at ten sites totaling approximately 1,350 MW. These ten sites are inclusive of the three steam generating stations. As such, all three steam generating stations also host combustion turbine generators.

This Chapter presents a description of the existing Northport generating station facilities and its current operations, as well as an assessment of current plant conditions. Of note is that while substantial assets remain dedicated to specific generating units at any given site, there may be significant shared assets at a site, including fuel handling facilities, buildings, certain switchyard equipment, and other balance of plant (BOP) structures and facilities. Consequently, repowering a generation plant – such as Northport - where the entire station cannot be shut down simultaneously presents construction sequencing challenges to allow some existing units to remain in service while other units are retired and demolished. This tends to extend the time required to complete a repowering, particularly so at Northport where construction sequencing is further challenged by site acreage constraints.

The Study used existing applicable and relevant information consisting of the current plant configuration and capabilities, repowering options and corresponding key attributes, and assumptions required to analyze relevant engineering, economic, and environmental factors, all of which are identified in the Study.

2.1 CURRENT PLANT DESCRIPTION

The Northport Power Station is located on Waterside Ave in the town of Huntington along the north shore of Long Island in Suffolk County, NY. The parcel of property on which Northport is located totals approximately 250 acres, of which approximately 75 acres is usable for a repowering. The steam units include four dual-fuel Combustion Engineering boilers with four General Electric (GE) turbine-generators each of 375 MW nameplate capacity. Also onsite is a single 16 MW GE Frame 5 gas turbine, combining for a station total of 1,516 MW. The units at Northport are operated under the terms of the PSA and were commissioned on the following dates:

- Steam units 1, 2, 3, and 4 were commissioned in 1967, 1968, 1972 and 1977, respectively.
- The 16 MW GE Frame 5 gas turbine was commissioned in 1967.

Starting in 1993 the capability to burn natural gas was added to the steam units, giving them the ability to burn either natural gas or fuel oil. The units were converted to burn natural gas per the following schedule;

- Unit 1- June 1998
- Unit 2- May 1995
- Unit 3- February 2003 (partial), May 2008 (full)
- Unit 4- May 1993

The steam units are fueled with both 0.5 percent low sulfur No. 6 oil and natural gas. Natural gas is supplied to the four steam units by a common Iroquois high pressure 1,400 psig gas pipeline and a common meter and regulating station that reduces pressure to 300 psig. No. 6 fuel oil is delivered to the steam units via ship through an offshore unloading terminal approximately two miles from the site in the Long Island Sound. The simple cycle gas turbine is fired on No. 2 fuel oil only, delivered through the same offshore unloading facility as No. 6 oil for the steam units. Makeup water to the station is supplied by city water supply that is processed through a common demineralizer and reverse osmosis system for the four steam units.

Northport has five tanks for storage of No. 6 fuel oil, but tanks 1 through 3 have been drained and retired. Tanks 4 and 5 remain in service. The No. 2 oil for the gas turbine unit is stored in a separate, dedicated tank. As per the arrangements between LIPA and Grid, stored fuel oil is owned by LIPA.

The Northport site is the tie point for a submarine transmission cable connecting across Long Island Sound to Norwalk Harbor in Connecticut. These cables enter the site north of the existing substation. The Iroquois natural gas pipeline traverses the site along with the Eastchester line that leaves the site and is routed under the Long Island Sound. The existing units are once-through cooled with intake from the Northport basin and discharge through a discharge canal to the Long Island Sound. The electrical point of interconnection is to an on-site 138kV LIPA substation.

PSEG LI maintains the station's switchyard and LIPA owns the main power transformers and the high side going to the switchyard. Grid owns the low side power line up to the main power transformer as well as startup and auxiliary transformers. Among numerous plant systems and equipment, Units 1 & 2 and Units 3 & 4 have, for example, separate control rooms, AC and DC electrical systems, balance of plant air supply, and circulating water and steam supply.

Since certain repowering scenarios require the staged demolition of Northport units and the construction of new units, it is important to recognize that there are certain common equipment and facilities among the units at Northport. Such common equipment and facilities include, for example:

- Natural gas supply line, gas heaters, filters and meter and regulating station – shared across the steam generation units.
- Fuel oil offshore unloading dock (located in the Long Island Sound) and supply pumps shared across the steam generating units and the GT unit.
- Fuel oil tanks 4 and 5 are shared among the steam units.
- Turbine building for the steam units with two overhead turbine cranes
- Common circulating water discharge dilution pumps and piping, which are required to maintain the circulating water discharge permit temperatures in the discharge channel for the steam units.
- Service water system with two pumps per unit
- Station waste-water facility
- Fire water protection system with storage tank supplied by city water and common fire pumps for the station
- Building heating
- Station security fencing and cameras
- City water supply and associated demineralizer water system with each unit having a condensate storage tank with cross tie capability
- Emergency electrical generators (2)
- Soot blower air compressor

Disposition of all of the above equipment and systems was considered when developing the repowering buildout and schedule.

2.2 CURRENT PLANT OPERATIONS

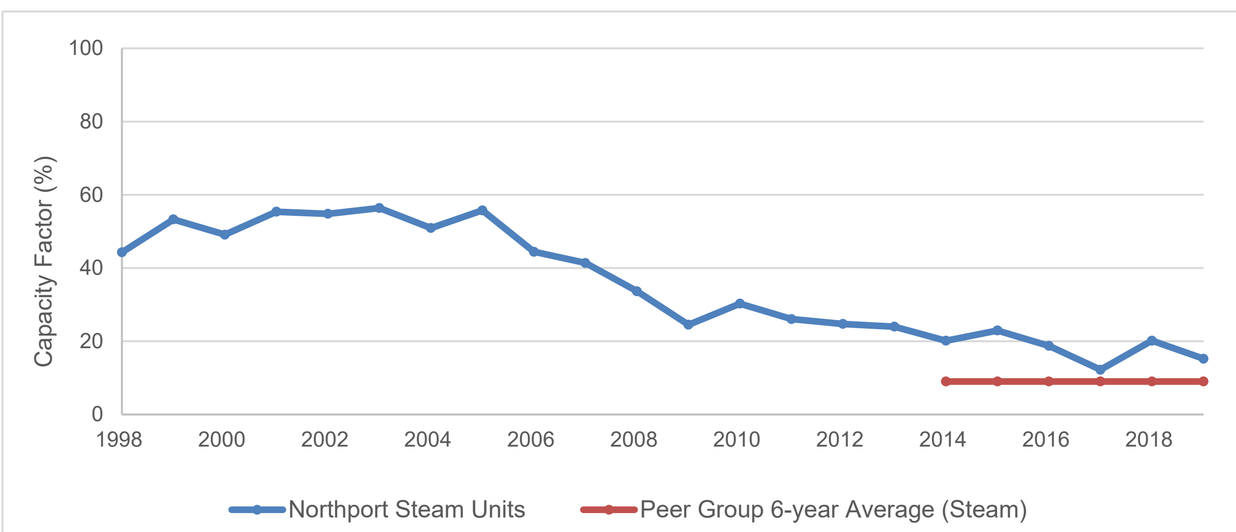
The station is economically dispatched by the NYISO. Each steam unit normally operates from a minimum load of 100 MW to a design load of 363 MW. The guaranteed ramp rate in the normal operating range is 4 MW per minute. The station provides ancillary services in the form of voltage support services, frequency regulation, and 10-minute synchronous reserve response. The full-load heat rate for Units 1, 2, 3, and 4 is approximately 10,200 Btu/kWh when burning natural gas.

The steam units follow a seasonal operational trend. Seasonal variations include higher summer-month and peak winter-month operations when ambient temperatures are high and low, respectively. During the spring and fall months, capacity factors, conversely, are low.

To assess the performance of the Northport steam units, they were compared to 25 comparable steam units operated by 19 other utilities during the period 2014 through 2019. Details of the benchmarking comparison are provided in Appendix A.[11] Of the key performance statistics, relevant comparisons include those for Equivalent Availability Factor (EAF), Capacity Factor (CF), and Equivalent Forced Outage Rate – demand (EFORd). These factors and rates provide a consistent way to compare the performance and condition of comparable power generation units. CF is defined as the ratio of a unit's actual output over a period of time to its potential output if it were to operate at full capacity continuously over the same period of time; EAF indicates the percentage of time the unit is able to run, accounting for both planned and unplanned down time; and EFOR-d indicates how often a unit cannot run when it is called to run, which is typically considered the best indicator of a unit's reliability.

As shown in the Figure 2-1, below, the Northport's station's net capacity factor shows a relatively steady decline from a high of 55.8% in 2005 to 15.2% in 2019. However, a comparison of recent (2014 – 2019) CF performance between Northport and the peer group shows Northport with a six-year average of 18.2% versus 9.0% for the peer group.

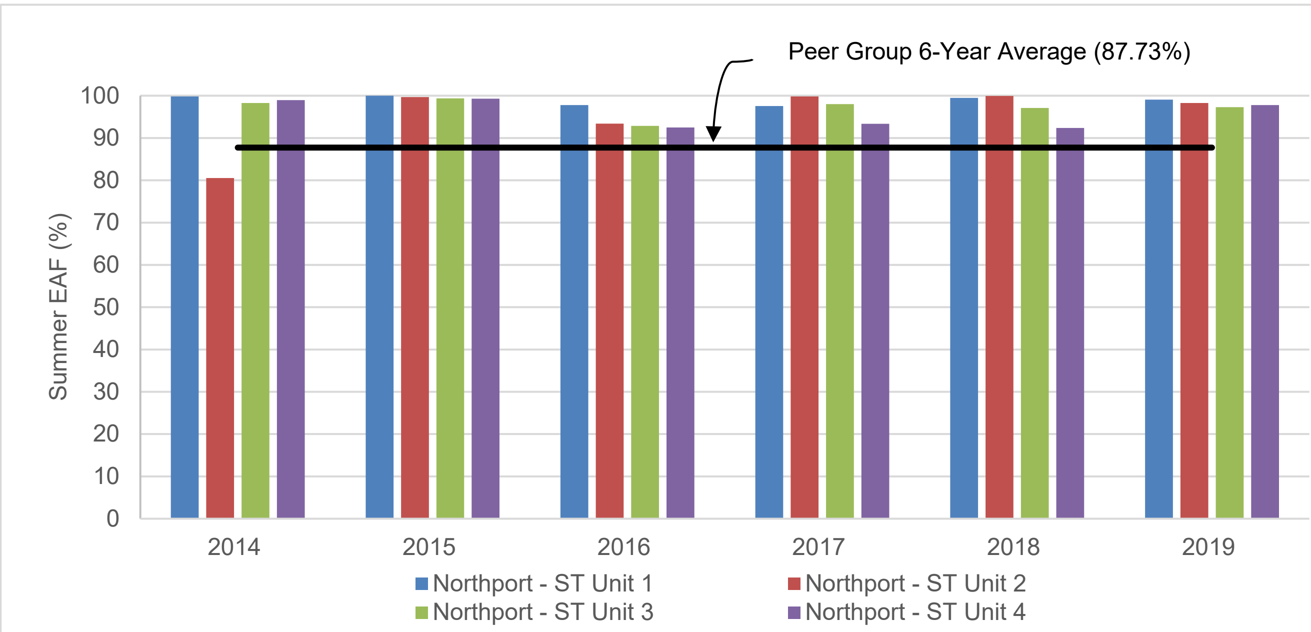
Figure 2-1: Northport Steam Units: Historical Capacity Factors



[11] Note that the "20 utilities" and "29 units" shown in Appendix A include National Grid and the four (4) Northport steam units.

Equivalent Availability Factor (EAF) combined with the operating philosophy for a unit can be used to better understand a unit's performance. Given the higher demand for electricity in the summer months, Grid works to maximize EAF from June 1 through August 31. Accordingly, it will schedule planned outages and major unit overhauls during the fall, winter, and spring months. Figure 2-2 shows Northport's EAF during the three summer months during the years 2014 - 2019.

Figure 2-2: Northport Steam Units: Summer Equivalent Availability Factor



Northport's EAF performance from 2014 - 2019 for the months of June, July and August was excellent, averaging 96.8% compared to an annual EAF of 87.7% for the peer group (a higher percentage is better), and reflects the results of Grid's sound operating and maintenance philosophy. These EAF values also are consistent with Northport's annual average EFOR-d performance for the same period, a low 3.55%, comparing favorably to the peer group mean of 13.09% (a lower percentage is better) and supports the independent condition assessment prepared by RCM Technologies, Inc. (RCMT) described below in Section 2.3.

Northport steam units operate in compliance with all required permits. There are multiple permits issued by the New York State Department of Environmental Conservation (NYSDEC), primarily covering air emissions, water use and discharge, and storage of liquid fuel. The air permit sets limits based on pollutant and fuel type. Sulfur dioxide (SO_2) emissions are directly proportional to the sulfur content of the residual fuel oil; the current limit is a maximum sulfur content of 0.5%. Though there is no unit specific NOx emissions rate limit for these units, there is a regulatory target of 0.15 lbs/MMBtu regardless of fuel. On gas, these units typically operate at 40% - 50% below the regulatory target. When combusting No. 6 fuel oil, the units normally emit about 0.15 lbs/MMBtu NOx. Water discharges are limited for various physical and chemical constituents, typically pH, oil and grease, total suspended solids and various metals. Air emission and water discharge data are reported to the US Environmental Protection Agency (USEPA) and/or the NYSDEC on quarterly and monthly basis with any permit limit exceedances noted. The information is available to the public on various government databases. The steam units are once-through cooled with seawater from the plant's intake structure and discharged to Long Island Sound. Aquatic protection for the cooling water intake system has been approved by the NYSDEC and technologies and operational controls are in place to minimize adverse impacts.

In terms of major capital expenditures, the circulating water screen system 316b capital upgrade for Units 3 and 4 has been completed. The circulating water screen system 316b capital upgrade for Units 1 and 2 has been approved with work scheduled to be complete on Unit 1 in the fall/winter of 2021/2022 and on Unit 2 in 2021. In addition, the Unit 4 steam turbine major overhaul was completed in February 2019.

2.3 CONDITION OF EXISTING FACILITIES

RCMT performed a high-level condition assessment in 2014 of Grid's power generation units under contract to LIPA through the PSA, which included the Northport units.[12] Overall, the condition assessment determined that the units could reliably operate at least until expiration of the PSA contract in 2028. This conclusion was based in part on Grid's continued application of its capital and Operations & Maintenance (O&M) programs, which determine how much will be spent on specific systems, maintenance issues, and capital projects, its Condition Assessment Program (CAP), and its Root Cause Analysis (RCA) program.

Grid confirmed that the programs noted above are still in place, the inspections/major overhauls described in the report occurred without finding significantly adverse conditions, and that the O&M and capital spending levels have either been implemented as planned or changed in accordance with CAP and RCA program requirements. The benchmarking report provided in Appendix A shows that the operational performance of the Northport units compares favorably to similar units, further supporting the conclusions of the RCMT assessment. Accordingly, the conclusions reached in the RCMT high level condition assessment – even though performed in 2014 - are considered to remain valid and the Northport plant can reasonably be expected to operate reliably at least through the termination of the PSA contract and into the 2030s.

LAST PAGE OF CHAPTER 2.

[12] See Appendix B for a redacted version of the RCMT's report.

3. A CHANGING ENVIRONMENT

Cost, efficiency, reliability, and environmental characteristics are critical elements when considering whether to move forward with a new power plant. They are not, though, the only factors. In addition, consideration, particularly in New York, must be given to the breadth and magnitude of ongoing changes in the electric power generation, transmission, and distribution sectors. These changes have a significant impact on decision making relative to repowering Northport, or any other plant on the system. The type and nature of key changes, and their attendant uncertainties, are presented below. In this Chapter we also discuss LIPA's existing capacity and resource need in view of the changing environment.

3.1 STATE INITIATIVES

The State has several important, ongoing initiatives related to the electric generation sector. These initiatives include:

- **Climate Leadership and Community Protection Act (CLCPA):** The CLCPA was signed into law in July 2019 and establishes some of the most aggressive clean energy and GHG reduction goals in the nation. The CLCPA effectively puts New York on a path towards carbon neutrality. A list of some of the major goals established by the CLCPA are listed in Table 3-1 below.

Table 3-1: CLCPA Goals

CLCPA Goal
85% reduction in GHG emissions by 2050
40% reduction in GHG emissions by 2030
100% carbon free electricity generation by 2040
70% electricity generation from renewable energy resources by 2030
9,000 MW of offshore wind by 2035
3,000 MW of energy storage by 2030

6,000 MW of distributed solar by 2025
185 trillion BTU increase in on-site energy savings by 2025

- **State Energy Plan (SEP):** Intended to coordinate all State agencies' efforts affecting energy policy to advance the REV agenda. On December 18, 2019, the NYS Energy Planning Board approved issuing a Draft Amendment to the 2015 State Energy Plan, to incorporate the new clean energy goals established under the Climate Leadership and Community Protection Act.
- **Reforming the Energy Vision (REV):** A Public Service Commission (PSC) policy framework intended to reorient and reform both the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets and is consistent with the SEP.
- **NYSERDA's New York State Offshore Wind Master Plan (Master Plan):** The Master Plan was released by NYSERDA in January 2018 and presented the State's comprehensive roadmap to encourage the development of 2, 400 MW of offshore by 2030. The offshore wind goal has since been increased to 9,000 MW by 2035 via the CLCPA.
- **Clean Energy Standard (CES)**: A PSC Order issued in August 2016 adopting the SEP goal that 50% of New York's electricity is to be generated by renewable sources by 2030. The goal has now been increased to 70% by 2030 through the CLCPA.
- **Offshore Wind (OSW) Standard (OSW Standard):** A PSC Order issued in July 2018 adopting the state's goal of developing 2,400 MW offshore wind by 2030. The goal adopted by the OWS Standard has been expanded to 9,000 MW of offshore wind by 2035 through the CLCPA.

With the CLCPA now signed into law, New York has a clear direction on the environmental performance that will be expected of its power system in the future - that is, 70% electricity generation from renewable energy resources by 2030 and 100% carbon free electricity generation by 2040. The CLCPA goal of an 85% reduction in statewide GHG emissions by 2050 also indicates that there almost certainly will be a significant

increase in the electrification of New York’s economy and a consequent demand for even greater amounts of carbon free electricity. Nevertheless, while the CLCPA goals put New York on a path towards carbon neutrality, there still is a high degree of uncertainty as to the implementation plans associated with it and other related State-level initiatives. It is expected that it will take a few years for these plans to fully unfold and for their market and system implications to be fully understood.

Despite the uncertainties, initiatives in support of these ambitious CLCPA goals are moving forward and will have a major impact on New York’s power system. For example, the CLCPA’s 9,000 MW goal of offshore wind by 2035 creates a focus on offshore wind development off of Long Island. In furtherance of that goal, NYSERDA completed an initial solicitation in October 2019 executing two contracts totaling 1,696 MW of offshore wind, 880 MW of which will be injected into Long Island. The continued development of New York’s offshore wind resources is expected to bring major operational changes to LIPA’s transmission and distributions system.

The types, amounts, and location of new generation, energy storage, demand response, or other distributed technologies that may be required to meet all of the CLCPA goals are yet unknown but, if the goals are met, are likely to result in an electric system significantly different than the current configuration.

3.2 LIPA COMMITMENTS

LIPA has been working for years to bring clean energy to Long Island and is committed to supporting the goals of the CLCPA. For example:

- In 2016, LIPA issued a Feed-in-Tariff (FIT) solicitation for commercial solar photovoltaics (i.e., FIT III). As of January 31, 2020, there were 35 commercial solar photovoltaics projects totaling 20 MW accepted into the FIT III program.
- LIPA’s PPA with Orsted adds 130 MW of offshore wind from the South Fork Wind Farm.
- LIPA’s 2015 Renewables RFP resulted in the selection of two solar photovoltaic projects, a 22.9 MW project that was recently approved by the LIPA Board of Trustees and a 36 MW project that is in Article 10 proceedings.

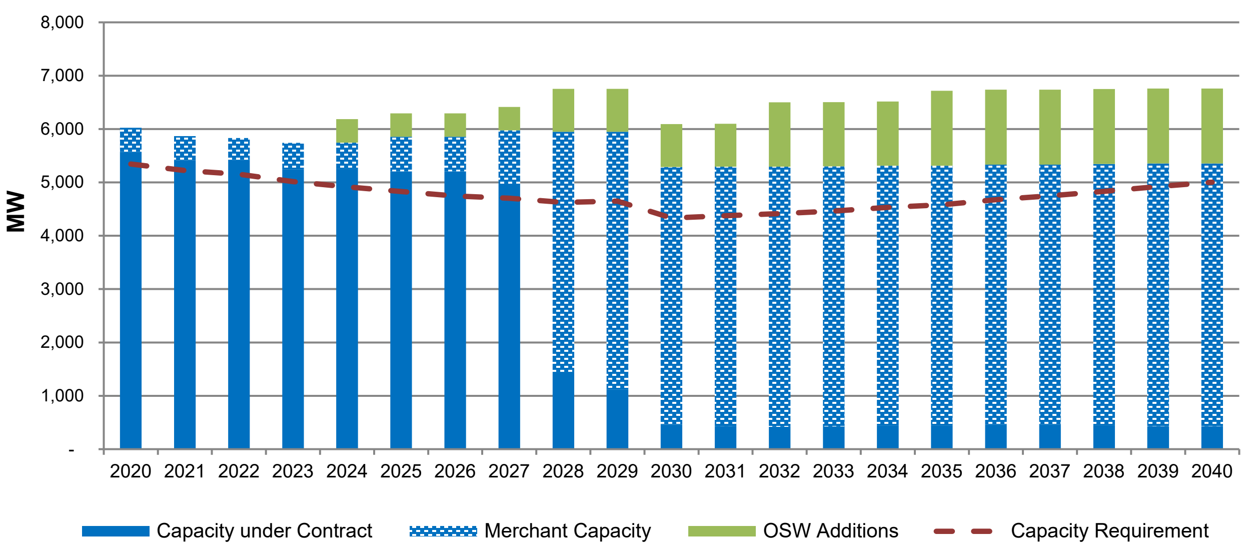
- In 2020, LIPA intends to issue a new solar communities' FIT program (i.e., FIT V) for the interconnection of up to 20 MW of photovoltaic resources, and recently issued an RFI requesting input from interested parties on the development of an energy storage resources RFP to be issued later in 2020 for up to 175 MW of energy storage capacity by 2025.

In addition to the above initiatives, LIPA continually evaluates its position in the market, its resource need, and its renewable goals and commitments, all of which are affected by the CLCPA and other related State-level programs and market initiatives.

3.3 EXISTING CONTRACTS & RESOURCE NEED

Due to the uncertainty in the next several years over the pace, timing, and magnitude of technology, market and regulatory changes there is a significant benefit to LIPA to keep open as many options as possible to enable selection of the best choices for meeting its obligations at the lowest cost for its customers. Figure 3-1 illustrates the flexibility LIPA has to defer making significant capital decisions until there is more certainty in policy and regulatory requirements, as well as to take advantage of ongoing technology and industry development. Notably, under the assumed conditions, LI has excess capacity for reliability purposes at least thru 2040.

Figure 3-1: LI Capacity Resources*

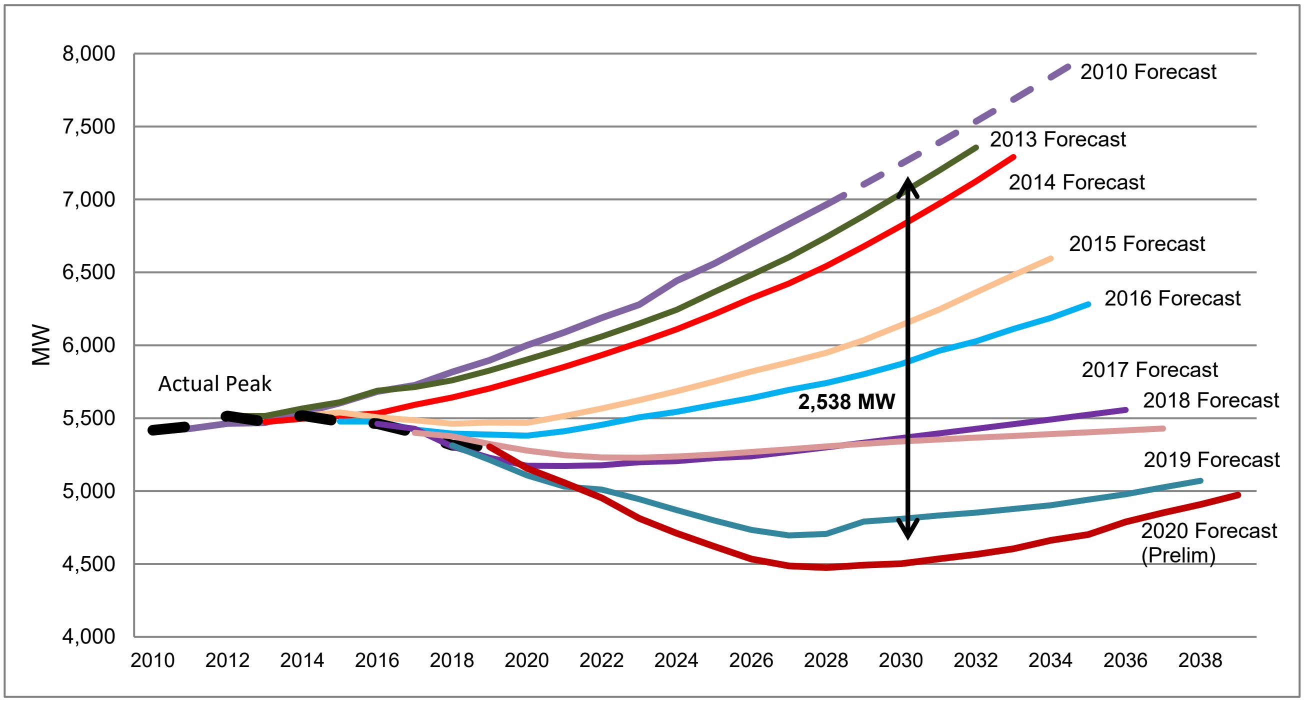


*For the purpose of the economic analysis, it was assumed that the terms and conditions of the PSA would extend through 2040.

3.4 PEAK LOAD FORECASTS

The first and foremost goal of LIPA is to maintain system reliability. Doing so efficiently, economically, and in an environmentally sensitive manner is also critical. Maintaining a reliable system is underpinned by having the appropriate amount of reliable generating capacity, or access to such capacity, to serve anticipated load and having the ability to deliver the energy to the customer. In terms of the need for capacity, a key input is the long-term peak load forecast. The forecast provides a planning target that, along with other factors, dictates the need (or not) for additional capacity. As shown in Figure 3-2 below, LIPA's peak load forecasts reveal dramatic year-on-year declines over the past seven years.

Figure 3-2: LIPA Peak Load Forecasts



Econometric forecasts for Long Island (e.g., number of households, employment, gross metro product) and the projected increase in electric vehicles penetration provide impetus for increasing electric demand in the foreseeable future. However, this growth is expected to be more than offset during the next decade by the impacts of increasing penetration and effectiveness energy efficiency, renewables (behind-the-meter solar PV and batteries), and load modifier programs leading to dramatic reductions in peak load and energy forecasts vis a vis earlier years. For example, the peak load forecast for 2030 has been reduced by 2,538 MW when comparing the 2013 forecast to the preliminary 2020 forecast. The result of these changes is that based on reliability considerations and assuming LIPA's current generation portfolio remains in place, LIPA has significant surplus capacity through 2040. Consequently, exclusive of local conditions, system reliability considerations do not drive a need for a repowered Northport.

LAST PAGE OF CHAPTER 3.

4. TECHNOLOGY EVALUATION & REPOWERING SCENARIOS

The Northport repowering analysis was conducted in a political, regulatory and economic environment significantly different than that associated with the Barrett and Port Jefferson repowering studies. Politically, New York State has made substantial changes to its renewable energy and emission reduction goals since 2017, most notably through the recently enacted CLCPA. The specifics of the CLCPA are discussed in Chapter 3, Changing Environment, but certain aspects, such as achieving 70% of total state-wide electricity production from renewable sources by 2030 and 100% carbon free emissions from electricity production by 2040, provide ample evidence of the aggressive nature of the State's goals. The regulatory environment also has become more active as state agencies intensify their efforts to rapidly develop plans and processes to successfully execute state goals. And economically, continued cost declines in renewable technologies are underpinning the growing penetration of renewable energy into the state's and the nation's resource mix.

In recognition of CLCPA mandates, which effectively eliminate the use of all carbon emitting energy resources by 2040, it was necessary to first understand whether there was the potential to employ renewable resources at the Northport site and, if so, to what degree. Following that assessment, repowering scenarios were developed that reflected the reality of feasible and economic implementation of repowering technologies, as well as practical site considerations (e.g., available usable acreage).

The following sections describe the results of the renewable technology evaluation that was conducted and the repowering scenarios that were subsequently developed.

4.1 TECHNOLOGY EVALUATION

Given that any repowering of Northport needs to take into account CLCPA goals, the potential for renewable energy production at Northport from a variety of technologies was evaluated. PSEG LI and Grid contracted with Power Engineers, a leading engineering design and evaluation firm, to examine the practical potential of deploying any of ten (10) different renewable technologies at Northport. The ability to deploy conventional technologies at Northport was a 'given', since gas-fired steam units and a combustion turbine unit currently exist at the site. The renewable technologies examined included the following:

- Solar Photovoltaic

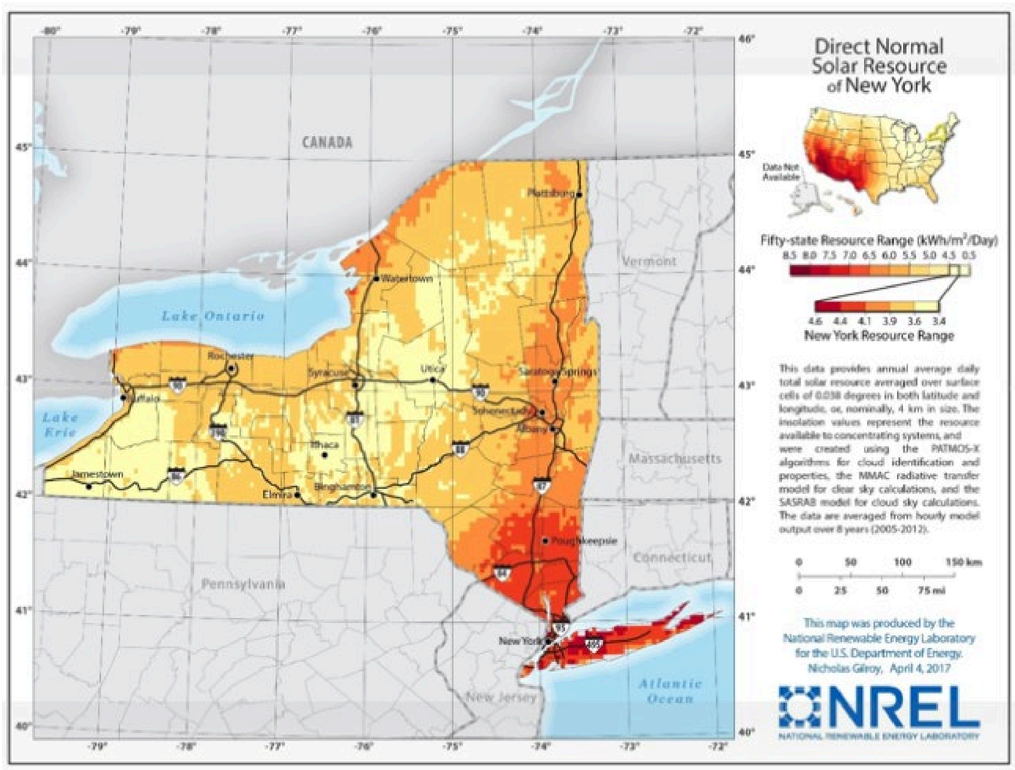
- Solar Thermal
- Onshore Wind
- Hydroelectric
- Geothermal
- Tidal
- Wave
- Ocean Thermal
- Fuel Cells
- Offshore Wind

The following provides brief descriptions of the potential application at the Northport site of the technologies identified above.

Solar Photovoltaic

The Northport site is a relatively flat site that according to the National Renewable Energy Laboratory (NREL) is in the higher range of solar irradiation when compared to the rest of New York State, as shown in Figure 4-1.

Figure 4-1: NREL's Direct Normal Solar Resource of New York

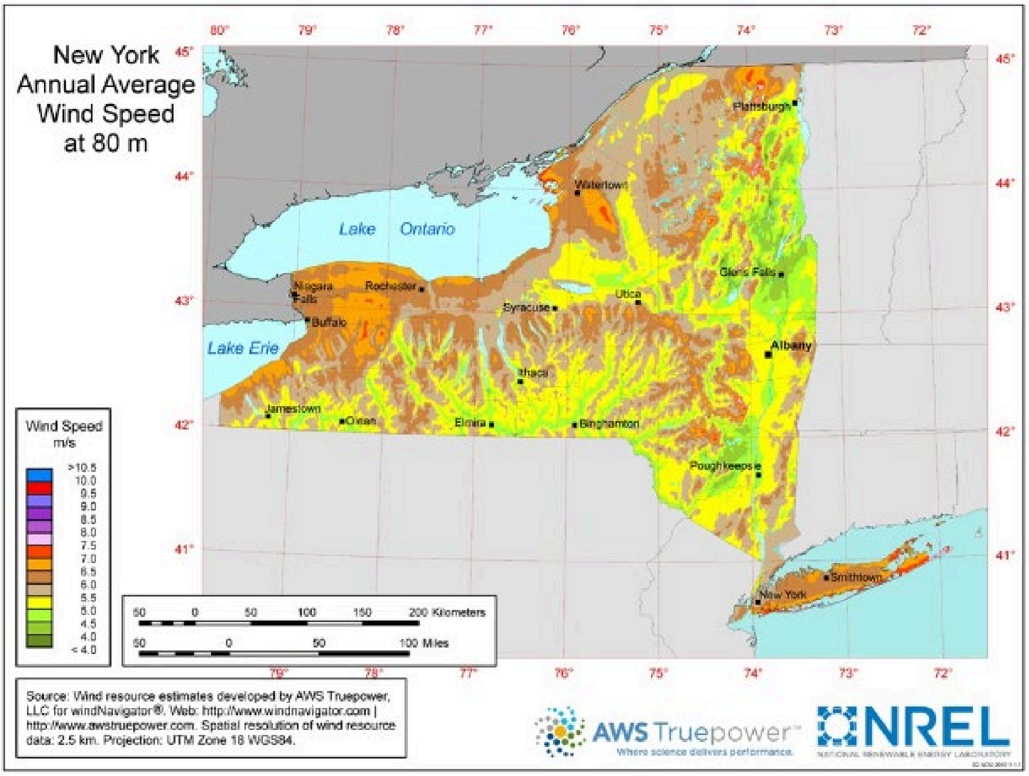


On average, solar installations require approximately 5 acres to support the installation of 1 MW of solar panels. The Northport site, though, has approximately 75 acres of usable land area (this includes the footprint of structures subject to demolition). Therefore, the approximate maximum capacity for the site is 15 MW, which is only 1% of existing plant capacity, a de minimis amount in the context of a full repowering.

Onshore Wind

The Northport site is conducive for onshore wind installations given its location along the coastline. As noted in the NREL map below, the site has a moderate average wind speed compared to the rest of New York State.

Figure 4-2: NREL's New York Average Wind Speed at 80 m



Wind turbines require approximately 9 rotor diameters spacing between turbines to avoid impacting each other. Onshore wind turbines of approximately 2 MW each are typical for this type of locations. Given the spacing requirements and shape of the site, it could at most support two 2 MW turbines, totaling 4 MW of capacity, again negligible in amount compared to the site's existing capacity.

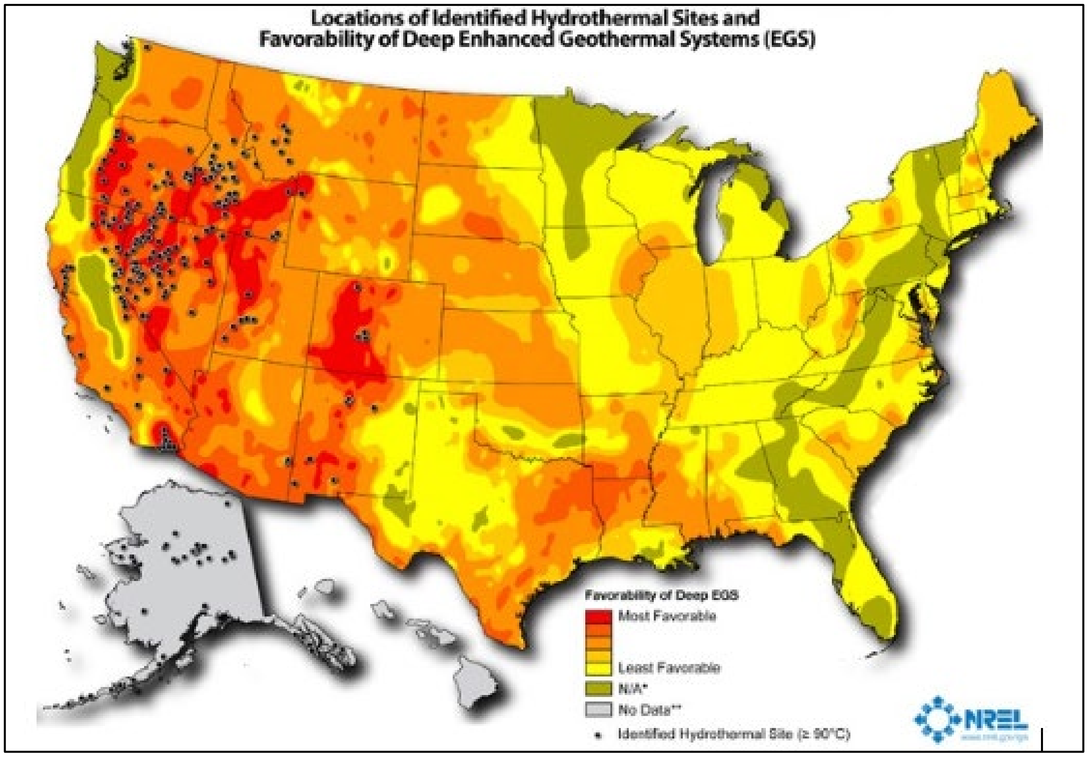
Hydroelectric

The Northport site is approximately 7ft above sea level (ASL), therefore it does not have potential for generating hydroelectric power.

Geothermal

As noted from the map below, NREL gives the Long Island Area a "Least Favorable" rating for potential geothermal resources. There seems to be little to no potential for installing a geothermal power generation resource of significant size at the Northport site.

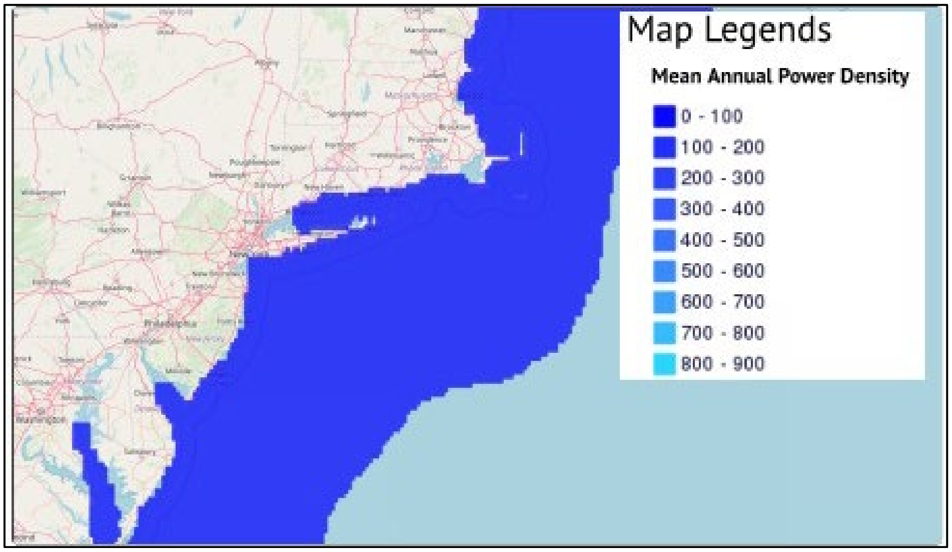
Figure 4-3: NREL's Geothermal Resource of the United States



Tidal Energy

Tidal energy is charted by NREL and provided through its Marine and Hydrokinetic Atlas (Atlas), an interactive mapping tool designed and developed by NREL to help explore the potential for marine and hydrokinetic resources. The Atlas was used to obtain the map below.

Figure 4-4: NREL's Mean Annual Power Density for Tidal Energy

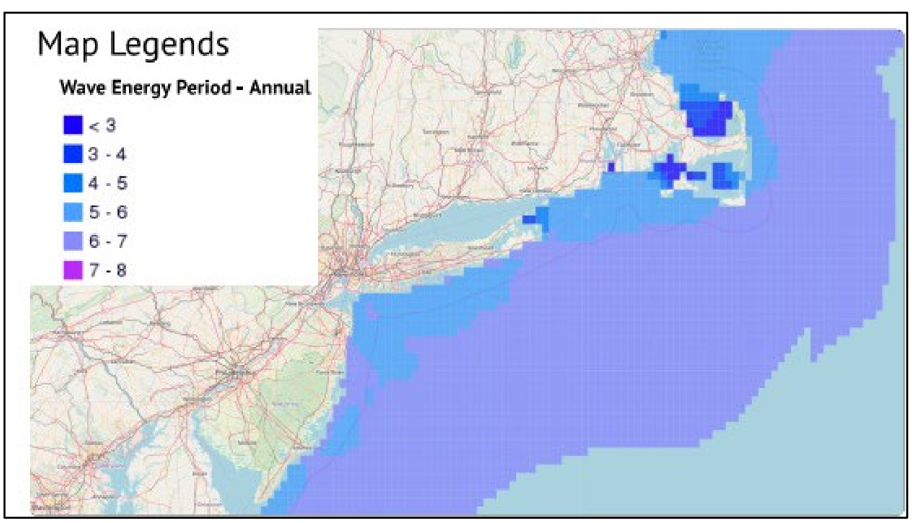


As noted from the data presented, the mean annual power density for tidal energy in the Long Island Sound is at the low end of the scale. Given the site's location in the Long Island Sound, there is little to no potential for the installation of a Tidal Energy system at the Northport station.

Wave Energy

The potential for wave energy is charted by NREL and provided through its Atlas. The Atlas was used to obtain the map below.

Figure 4-5: NREL's Wave Energy Potential

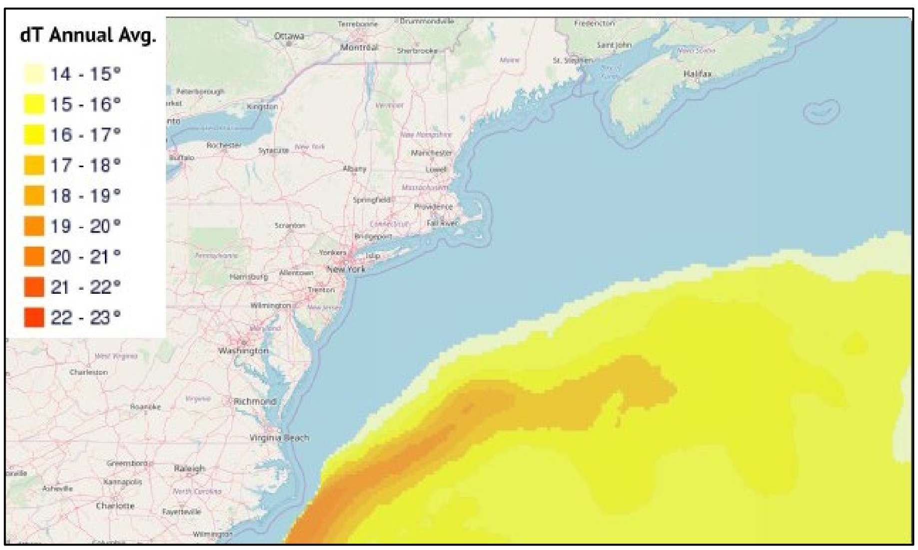


As shown in Figure 4-5, the annual wave energy potential in the Long Island Sound is not mapped by NREL, but the eastern end of Long Island indicates an area of some of the lowest potential wave energy. It is assumed that the wave energy in the Long Island Sound is less than at the east end of Long Island, hence there is little to no potential for the installation of a tidal energy system at the Northport station.

Ocean Thermal

The potential for ocean thermal energy is charted by the NREL and provided through its Atlas. The Atlas was used to obtain the map below.

Figure 4-6: NREL's Ocean Thermal Energy Potential



Ocean thermal systems work best in areas with a temperature difference of around 20°C between surface and deep water. As shown in Figure 4-6, NREL does not chart the temperature difference in the New York area. Note, though, that the temperature difference as far south as Delaware shows only a 14-15°C differential. It can be presumed that the area around the Long Island sound is significantly less. Therefore, there is little potential for the installation of an ocean thermal energy system at the Northport facility.

Fuel Cells

Fuel cells are included in the CLCPA so long as they use a non-fossil fuel, so potential sources are limited to fuels such as hydrogen or biofuels. The Northport site, though, does not have natural storage available to support a large hydrogen fuel cell installation, and a reliable source of biofuel that would be needed to support such a facility is not currently available in the area. Further, even if fuel could be sourced in the future, the site could likely support the installation of only up to approximately 50 MW of fuel cells given their current footprint.

Offshore Wind

While the Long Island Sound is not optimal for offshore wind, the Northport Station is situated such that it could serve as the interconnect point for offshore wind. The approximate 75 acres of usable area on the site could support the necessary converter station and substation expansion to interconnect a large offshore wind farm. Depending on the infrastructure upgrades required, there may also be space for simple cycle gas turbines to back up some portion of the offshore wind capacity.

Summary

Ten (10) renewable technologies were examined to determine the feasibility of their potential deployment at Northport. Exclusive of potentially interconnecting offshore wind at Northport, no technology was deemed practical largely due to the relatively restrictive site size and/or lack of appropriate natural conditions.

4.2 SCENARIOS

The Study developed six (6) alternative repowering scenarios, including Grid’s proposal (Scenario 3). In addition to the six alternative scenarios, a Reference Case, reflecting a long-term resource portfolio that included operating the Northport units ‘as-is’ (i.e., no repowering occurs) was developed. The results of each alternative were compared against those of the Reference Case to determine the relative effects of its implementation. Chapter 6, Repowering Provisions and Economic Viability, presents the results of those comparisons.

The inability to introduce sufficient renewable energy resources at Northport to replace the existing plant capacity affected the Study in that it limited the reasonably applicable technologies to conventional generation and batteries. Interconnecting offshore wind at Northport and upgrading the Northport-Norfolk Cable (NNC) intertie also were considered although, technically, use of these technologies does not repower the Northport units so much as replace a portion of existing capacity with offsite resources.

There were five (5) generating technologies used in the repowering analyses, each technology applicable to one or more scenarios (except for one scenario that represents the retirement of a single steam unit with no assumed replacement capacity). The technologies considered were:

- *Combined Cycle (CC) – 340 MW*: A '1x1x1' CC unit consisting of one GE 7F.05 combustion turbine generator with one heat recovery steam generator and one steam turbine generator with an air-cooled condenser.
- *Simple Cycle (SC) – 230 MW*: A single GE 7FA.05 combustion turbine.
- *Battery Energy Storage System (BESS) – 50 MW*: A 4-hour lithium-ion battery and rack system including, among other features, comprehensive site monitoring and control, and an advanced battery management system.
- *Offshore Wind (OSW) – 800 MW:*[13] An offshore wind facility injecting into Northport.
- *Northport-Norwalk Cable (NNC) Upgrade – 229 MW*: Upgrade NNC import/export from +/-200 to +/-429 MW for an increase of 229 MW.

The performance attributes of the CC, SC and batteries are shown in Appendix C. Both the CC and SC technologies have high thermal efficiencies and low emissions rates as befits the latest advanced combustion technology. The CC plant would use a closed loop cooling system and the total capacity of any scenario would not exceed the Northport substation exit capabilities. The proposed combustion turbines would be designed for operation from approximately 40% minimum load to 100% of nameplate rating. While there are no significant natural gas system upgrades required, a natural gas metering station and equipment would need to be installed. A 30-day interruptible natural gas supply was assumed.

In most scenarios it was necessary to stage construction and arrange new power blocks such that the existing units could continue to operate through the construction of the new power block that would replace it. Once decommissioned the existing units could be scheduled for demolition to make room for additional expansion phases. This sequencing, in some cases, caused a significantly extended construction time frame to completely deploy the technologies comprising the scenario.

The technologies and resource sizes comprising each scenario are shown below in Table 4-1.

[13] 800 MW represents nameplate capacity; the Unforced Capacity (UCAP) value was assumed to be 400 MW, i.e., 50 percent of nameplate.

Table 4-1: Repowering Scenarios: Capacity Retirements/Additions

Unit Type/Status	Unit Size	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
NP Units to be Retired	**NP 1 (375 MW)**	Y	Y	Y	Y	Y	Y
	NP 2 (375 MW)	---	Y	Y	Y	Y	---
	NP 3 (375 MW)	---	Y	Y	Y	Y	---
	NP 4 (375 MW)	---	Y	Y	Y	Y	---
Net Existing Capacity		**1,125 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**1,125 MW**
New CC	**340 MW**	1 ea.	2 ea.	2 ea.	1 ea.	2 ea.	---
New SC	**230 MW**	---	4 ea.	3 ea.	3 ea.	2 ea.	---
New BESS	**50 MW**	1 ea.	---	3 ea.	3 ea.	3 ea.	---
New OSW	**800 MW***	---	---	---	1 ea.	---	---
NNC Cable Upgrade	**229 MW**	---	---	---	---	1 ea.	---
Added New Capacity		**390 MW**	**1,600 MW**	**1,520 MW**	**1,580 MW****	**1,290 MW*****	**0 MW**
New Northport Plant Capacity		**1,515 MW**	**1,600 MW**	**1,520 MW**	**1,580 MW****	**1,290 MW*****	**1,125 MW**
COD Range of New Capacity		2025 - 2026	2026 - 2032	2025 - 2034	2025 - 2034	2025 - 2034	---

* Nameplate capacity; UCAP capacity is assumed to be ~400 MW

** Assumed UCAP capacity for offshore wind

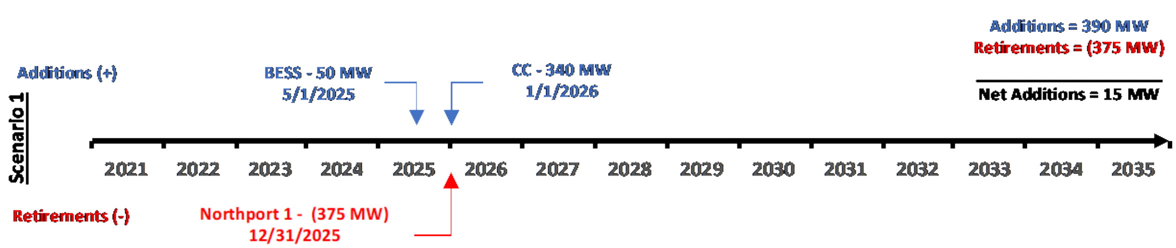
*** NNC cable upgrade does not count as UCAP capacity

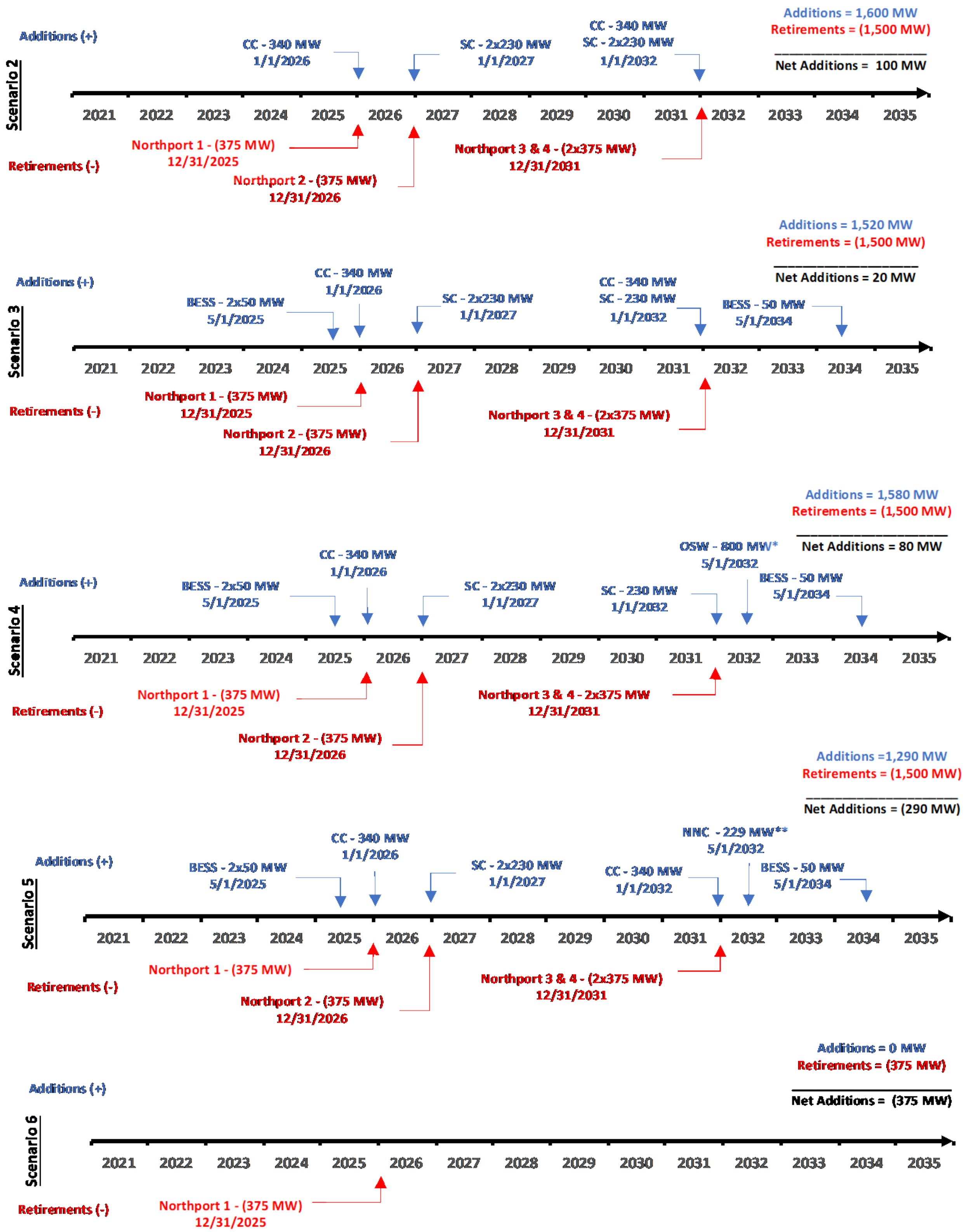
Note that for each Scenario the units to be retired are indicated by a "Y" in the table. (The absence of a "Y" indicates that the unit is not retired.) The "Net Existing Capacity" row is the total capacity associated with the existing units post retirement(s). "Added New Capacity" represents the total new capacity added in each Scenario and is determined by summing the amount of capacity associated with the specific type and amount of new capacity in a Scenario. "New Northport Plant Capacity" is the sum of the "Net Existing Capacity" and "New Northport Plant Capacity".

There are a few notable aspects of the Scenarios. First is the extended range of time for construction of the full complement of technologies which, for 4 of the 6 options, is between 12 and 14 years (starting from 2020). This extended period is due to limited site acreage and the consequent required staging of construction of the replacement capacity and the demolition activities associated with the existing capacity. This extended time frame has a significant impact on the time available (it is reduced) for Grid to recover project costs under the assumption that natural gas fired generation cannot be part of the State's resource supply mix by 2040 per the CLCPA. The shortened period to recover costs translates to increased annual revenue requirements up to 2040. Second, offshore wind is the only renewable technology that is any way practical at Northport (technically, offshore wind is not actually *at* Northport, rather the energy produced is injected into the Northport substation), again due to site constraints. Finally, for Scenarios 2 through 5, the commercial operation dates of the final elements of each scenario extend into the early 2030's which, depending on progress achieved in reaching CLCPA goals, could affect the long-term economics of those scenarios.

Regarding the extended time required for construction associated with most Scenarios, Grid's proposal, Scenario 3, provided a useful template for understanding in more detail some of the non-construction related activities that drive the schedule. Preliminarily, it is anticipated that execution of Grid's proposal would occur in three phases. As shown in Appendix D, each phase contains activities related to Article 10 permitting, demolition of fuel tanks and/or demolition of existing units, along with related construction work. In combination, these tasks, sequenced both inter and intra-phase, extend the time required to fully bring the new capacity on-line. Other scenarios would be similarly phased, as necessary, and show comparably long construction/demolition periods. Figure 4-7, below, presents timelines for each scenario and depicts when the major capacity additions and retirements are scheduled to take place.

Figure 4-7: Repowering Scenarios' Timelines: Capacity Retirements/ Additions





Scenario 2
Additions (+)
CC - 340 MW 1/1/2026
SC - 2x230 MW 1/1/2027
CC - 340 MW SC - 2x230 MW 1/1/2032
Additions = 1,600 MW
Retirements = (1,500 MW)
Net Additions = 100 MW
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Retirements (-)
Northport 1 - (375 MW) 12/31/2025
Northport 2 - (375 MW) 12/31/2026
Northport 3 & 4 - (2x375 MW) 12/31/2031
Scenario 3
Additions (+)
BESS - 2x50 MW 5/1/2025
CC - 340 MW 1/1/2026
SC - 2x230 MW 1/1/2027
CC - 340 MW SC - 230 MW 1/1/2032
BESS - 50 MW 5/1/2034
Additions = 1,520 MW
Retirements = (1,500 MW)
Net Additions = 20 MW
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Retirements (-)
Northport 1 - (375 MW) 12/31/2025
Northport 2 - (375 MW) 12/31/2026
Northport 3 & 4 - (2x375 MW) 12/31/2031
Scenario 4
Additions (+)
BESS - 2x50 MW 5/1/2025
CC - 340 MW 1/1/2026
SC - 2x230 MW 1/1/2027
SC - 230 MW 1/1/2032
OSW - 800 MW* 5/1/2032
BESS - 50 MW 5/1/2034
Additions = 1,580 MW
Retirements = (1,500 MW)
Net Additions = 80 MW
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Retirements (-)
Northport 1 - (375 MW) 12/31/2025
Northport 2 - (375 MW) 12/31/2026
Northport 3 & 4 - 2x375 MW 12/31/2031
Scenario 5
Additions (+)
BESS - 2x50 MW 5/1/2025
CC - 340 MW 1/1/2026
SC - 2x230 MW 1/1/2027
CC - 340 MW 1/1/2032
NNC - 229 MW** 5/1/2032
BESS - 50 MW 5/1/2034
Additions =1,290 MW
Retirements = (1,500 MW)
Net Additions = (290 MW)
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Retirements (-)
Northport 1 - (375 MW)
Northport 2 - (375 MW) 12/31/2026
Northport 3 & 4 - (2x375 MW) 12/31/2031
Scenario 6
Additions (+)
Additions = 0 MW
Retirements = (375 MW)
Net Additions = (375 MW)
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Retirements (-)
Northport 1 - (375 MW) 12/31/2025

* Nameplate capacity: UCAP capacity is assumed to be 400 MW
**NNC cable upgrade does not count as UCAP capacity.

In sum, while the scenarios are robust, they are designed to reflect the realities of what the site can actually accommodate in terms of resource type and capacity. Unfortunately, that does not allow for the inclusion of on-site renewable resources; what is feasible (i.e., conventional generation and storage) requires an extended time to design, permit, and construct, and new conventional generation is subject to early shutdown (i.e., by 2040) pursuant to the CLCPA mandate.

LAST PAGE OF CHAPTER 4.

5. ENGINEERING & ENVIRONMENTAL ANALYSIS

This chapter assesses the engineering and environmental elements of Grid's proposal to repower Northport (i.e., Scenario 3). It includes a description and details of the major plant components, operating performance, fuel supply, delivery, and storage, and transmission system requirements. This chapter also identifies the necessary permits and licenses required to build and operate the repowered plant, and the required supporting studies. Finally, the chapter includes a discussion on project implementation issues, such as constructability and the project schedule.

5.1 ENGINEERING CONSIDERATIONS

5.1.1 Proposed Repowering Option

The proposed Northport repowering project (i.e., Scenario 3, Grid's proposal introduced in Chapter 4) proposes that the existing steam Units 1 - 4 (1,500 MW total) are retired, demolished, and replaced with the installation of two 340 MW 1x1 GE 7F.05 gas-fired combined cycle units (CC), three 230 MW GE 7F.05 gas fired simple cycle units (SC), and three 50 MW lithium ion battery energy storage systems (BESS). The proposal assumes that the existing 16 MW gas-fired combustion turbine remains in place. Table 5-1 provides a summary of the existing units and major components at Northport and how they would be dispositioned under Grid's proposal.

Table 5-1: Disposition/Addition of Major Plant Assets: Scenario 3

Units & Components	Description & Comments	Total Current Output	Disposition	Total Repowering Output
Units 1, 2, 3 and 4	Four (4) 375 MW steam units with vintages ranging from 1967 to 1977.	1,500 MW	Retire & remove all four units	0 MW
GT1	GE Frame 5 gas turbine commissioned in 1967.	16 MW	Remain	16 MW
Combined Cycle (CC)	1 unit = 340 MW (1 SC CT, 1 heat recovery steam generator & 1 steam turbine)	0	2 new units	680 MW
Simple Cycle (SC)	230 MW CT	0	3 new units	690 MW

Units & Components	Description & Comments	Total Current Output	Disposition	Total Repowering Output
Battery Storage (BESS)	50 MW lithium ion battery	0	3 new batteries	150 MW
	Plant Output, Current & Repowered	**1,516 MW**		**1,536 MW***

* Total Repowering Output includes the existing 16 MW GT1 that will remain in service.

The combined cycle units would operate on natural gas and have ultra-low sulfur distillate (ULSD) fuel backup with an onsite ten-day storage capability. They would have advanced Dry Low nitrogen oxide (NOx) combustors for natural gas firing and water injection for NOx control on distillate (ULSD) fuel. A selective catalytic reduction system (SCR) and any other necessary emission controls would be included in the design. Additional specific design parameters include combustion turbine evaporative cooling, 100% steam bypass to the air-cooled condenser on the combined cycle units, auxiliary fin fan cooling, and key equipment redundancy to achieve high availability.

The final detailed design of the repowered plant would likely change from the high-level description provided herein due to the typical engineering progression as the repowering project moves from conceptual, through preliminary and subsequent detailed design phases. These changes are an expected part of any design process and would not materially impact the overall results of this Study.

5.1.2 Repowered Unit Operating Performance

Conceptual level performance data for both fuel types (natural gas and ULSD) and at various load conditions for the repowered plant (i.e., the proposed CC and ST units) based on Scenario 3 is provided in Appendix C, the Northport Repowering Attributes Summary. The matrix includes gross and net unit performance data for three temperatures (92F, 59F and 25F) for natural gas and distillate fuel (ULSD). The matrix also includes a summary showing emission rates (NOx, SO_2, CO, CO_2, PM, and NH_3). Also shown in Appendix C are the performance attributes for the 50 MW battery storage unit.

5.1.3 Fuel Supply, Delivery, and Storage

Natural gas to fire the new units would be supplied by means of the existing Iroquois pipeline with separate compression, regulation, and metering for each unit. Ultra-low sulfur diesel (ULSD) liquid fuel would be delivered by barge to the existing unloading facilities at the site and stored in two new fuel oil storage tanks of 10,000,000 gallons each. This would provide 100% capacity storage for ten days of full load oil firing on all new combustion turbine generators planned for the repowered site. The new tanks would be erected in the area of the existing #2 and #3 fuel oil tanks. The existing fuel oil tanks would be remediated and removed to make room for the new tanks.

5.2 TRANSMISSION SYSTEM

Grid's proposed Northport repowering project would approximate the overall capacity of the existing site. Since the overall site capacity would be increased but only by a small amount (approximately 20 MW), it is anticipated that the need for potential electrical system upgrades would be minimal, if any. To the extent that any individual phase of construction would result in a total steam plant capacity (i.e., remaining plus new) greater than 1,500 MW, given the mix of technologies and configurations that would be available for use upon completion of a construction phase, it was envisioned that through a combination of derating the existing units and the intermittent use of the BESS and/or simple cycle units that the export capacity would be balanced to limit total exports, if necessary. Of particular consideration would be the Phase 2 construction that when combined with the Phase 1 capacity, would exceed the total installed capacity of the existing Units 1 & 2. This may include, as noted, operationally derating the remaining Units 3 & 4 such that the overall plant capacity remains nearly the same. Electric power from each new unit would be stepped up to 138 kV and consolidated in a collector bus for each phase, such that there is a single interconnect to the corresponding location in the existing substation.

The proposed new facility configuration is not intended to exceed by any appreciable amount the current substation's exit capability. Accordingly, there are no significant changes or issues related to the existing substation structures, systems, and components or overall electrical interconnection.

5.3 ENVIRONMENTAL CONSIDERATIONS

5.3.1 Project Licensing & Permitting

The project would be subject to licensing and permitting under both, the New York State Department of Public Service (NYSDPS) and the New York State Department of Environmental Conservation (NYSDEC) regulations. The project would be considered a 'major electric generating facility' and subject to Article 10 of the New York State Public Service Law. Article 10 requires that the New York State Board on Electric Generation Siting and the Environment issue a Certificate of Environmental Compatibility and Public Need authorizing the construction and operation of major electric generating facilities following a detailed evaluation process. The project, though, would be considered a ‘repowering’ of an existing facility and therefore eligible for an accelerated review, but would still require air and water permits issued by the DEC. The two proceedings would be held jointly.

Article 10 proceedings roll up virtually all State and Local licensing and permitting requirements into a single process under a Siting Board. The process and application requirements are highly prescriptive, calling for forty-one (41) separate topics (see the list in Section 5.3.3) – from land use and air emissions to impacts of electric systems and telecommunications – that need to be covered in the application. For purposes of this study, each project phase (1A, 1B, etc.) was considered to be a separate licensing event estimated to take approximately 24 months, equating to six (6) separate Article 10 proceedings. However, a single proceeding for each phase might be possible at the time the selection is made.

The process begins with the development of a Public Involvement Program (PIP) designed to foster open communication with regulators, the public and other stakeholders. The applicant also issues a Preliminary Scoping Statement detailing the project scope, potential benefits, and impacts. The Scoping Statement undergoes a public comment period where municipalities and other stakeholders can provide comments. A Hearing Examiner then identifies formal intervenors who would be eligible to receive funding to evaluate the project. Prior to developing the formal application, the applicant, regulators and other interested parties would agree on stipulations intended to reach agreement on the type and extent of studies on environmental and community impacts that would be analyzed and reported in the application.

The application’s studies are comprehensive (see Section 5.3.3). Once the application is submitted and deemed complete the project would be evaluated based on the results of the studies. Intervenors would have the opportunity for funding and would be able to participate in the process. Any hearings would take place during this period. The NYSDEC permitting process for federally designated permits and other approvals would follow the Uniform Procedures Act, Article 70 of the Environmental Conservation Law (ECL).

A successful proceeding results in the issuance of a “Certificate of Environmental Compatibility and Public Need” by the Siting Board authorizing the construction and operation of the facility, as well as the issuance of the necessary air, water, and waste permits by the NYSDEC.

5.3.2 Required Permits

The following table provides a summary of anticipated environmental permits, approvals, and agency consultations required for the repowering.

Table 5-2: List of Permits and Approvals

Agency	Department	Permit/Approval	Agency Action
State	New York State Board on Electric Generation Siting and the Environment	Certificate of Environmental Compatibility and Public Need	Required for commencement of construction activities.
Federal	US Army Corps of Engineers (USACE)	Section 10 of the Rivers and Harbors Act of 1899/ Section 404 Clean Water Act	Required for structures or work in navigable waters within or under navigable waters of the US (i.e., existing discharge canal). Level of permitting (IP or NWP) will be based on impacts resulting from specific construction activities.
Federal	Federal Aviation Administration (FAA)	Determination of No Hazard to Air Navigation	Required pursuant to FAA Regulations, Part 77- Objects Affecting Navigable Airspace for construction cranes or other elevated structures exceeding 200 feet or to be used within proximity to an airport or heliport.
Federal	U.S. Fish and Wildlife Service	Section 7: Threatened and Endangered Species Review and Consultation	Provides a determination of whether Federally regulated species or their habitats are potentially present onsite. "Determination of No Effect" required to support issuance of USACE permits.
Federal	National Oceanic and Atmospheric Administration (NOAA)	NOAA Fisheries (formerly known as the National Marine Fisheries Service) Consultation	Required in support of any federal permit approval to confirm that there are no significant adverse impacts from the proposed construction and/or operations to marine resources.
State	NYS Department of State	Coastal Zone Consistency Determination	Required in support of issuance of NYSDEC and USACE permits and approvals to ensure consistency with designated uses of the coastal zone and applicable coastal zone policies.

Agency	Department	Permit/Approval	Agency Action
State	NYSDEC	SPDES Permit Modification for Construction and Dewatering Activities	Required for construction that will result in a disturbance of greater than one acre or the discharge of treated dewatering effluents. Notification is also required for the termination of permitted process wastewater or stormwater discharges.
State	NYSDEC	Article 15 - Use and Protection of Waters	Required for all work below mean high water line on protected streams.
State	NYSDEC	Tidal Wetlands Permit	Required for any work within coastal wetlands and their associated buffer.
State	NYSDEC or New York State Board on Electric Generation Siting and the Environment	Water Quality Certification	In accordance with Section 401 of the Clean Water Act, applicants for a Federal license or permit for activities that may result in a discharge into waters of the United States must obtain a water quality certification from the state agency charged with water pollution control indicating that the proposed activity will not violate NY State water quality standards.
State	NYSDEC	Threatened and Endangered Species Inventory Review	Consultation letter must be sent to the New York Natural Heritage Program (NYNHP), to determine if the project will impact any protected plant or animal species habitat. "Determination of No Effect" required to support issuance of NYSDEC permits.
State	NYSDEC	Major Oil Storage Facility Permit	From NYSDEC DER-11 - Procedures for Licensing Onshore Major Oil Storage Facilities, APPENDIX B.
State	New York State Office of Parks, Recreation and Historic Preservation (OPRHP)	Section 106 Cultural and Historic Resources Review and Consultation – "Determination of No Effect"	Provides a determination of whether cultural and/or historic resources are potentially present on site. Required for issuance of state and federal permits.
State	NYSDEC	PSD Part 231/Part 201 Air Permit	Submission to NYSDEC as required by the Clean Air Act and under NY State law and regulation.
State	NYSDEC	Registration of Storage Tanks	All stationary storage tanks at a facility must be registered with the Department per Part 596 regulations

Agency	Department	Permit/Approval	Agency Action
State	NYSDEC	Part 598: Notice of Closure	Chemical bulk storage notice requirement for the closeout of the acid tank.

Note: Any required county and municipal approvals will be determined during Article 10 process.

5.3.3 Permitting Studies

As noted, the Article 10 Certificate process is very comprehensive and requires the preparation of numerous studies to assess any potential impacts resulting from a proposed project, including studies on air emissions and water. The application is functionally divided into 41 exhibits that must adequately address the following specific topics:

1: General Requirements
2: Overview and Public Involvement
3: Location of Facilities
4: Land Use
5: Electric System Effects
6: Wind Power Facilities
7: Natural Gas Power Facilities
8: Electric System Production Modeling
9: Alternatives
10: Consistency with Energy Planning Objectives
11: Preliminary Design Drawings
12: Construction
13: Real Property
14: Cost of Facilities
15: Public Health and Safety
16: Pollution Control Facilities
17: Air Emissions
18: Safety and Security
19: Noise and Vibration
20: Cultural Resources
21: Geology, Seismology and Soils
22: Terrestrial Ecology and Wetlands
23: Water Resources and Aquatic Ecology
24: Visual Impacts
25: Effect on Transportation
26: Effect on Communications
27: Socioeconomic Effects
28: Environmental Justice
29: Site Restoration and Decommissioning
30: Nuclear Facilities
31: Local Laws and Ordinances
32: State Laws and Regulations
33: Other Applications and Filings
34: Electric Interconnection
35: Electric and Magnetic Fields
36: Gas Interconnection
37: Back-Up Fuel
38: Water Interconnection
39: Wastewater Interconnection
40: Telecommunications Interconnection
41: Applications to Modify or Build Adjacent

The project also requires air and water permits issued by the NYSDEC. This would include the preparation of an application and supporting studies for a Part 201/Part 231 Prevention of Significant Deterioration (PSD) Permit. Part 201 requires existing and new sources to evaluate minor or major source status and evaluate and certify compliance with all applicable requirements. State Pollutant Discharge Elimination System (SPDES) Permits for Construction Stormwater and Industrial Discharge would also be required.

5.3.4 Air Emissions and Water Characteristics

Northport currently complies with all existing emissions-related permits. The proposed repowered plant, though, offers fuel and emissions benefits relative to the existing facility. Environmentally, the repowered units lower CO_2 emission rates (lbs/MWh) by approximately 35% and NOx emission rates by 90% and would displace emissions from other plants. Repowering also will utilize an air-cooled condenser (ACC), thereby eliminating the existing once-through cooling system.

Of note, the proposed plant would have greater total emissions than the existing facility because of its expected higher capacity factor, i.e., its rate of emissions would be lower, but because it is more fuel efficient, it would operate more and produce more energy (i.e., megawatt-hours, or MWh); hence, total emissions from the site would be higher. So, paradoxically for those living in proximity to the plant, while a repowered unit would be more environmentally friendly from an emissions perspective on a unit basis (i.e., lbs of emissions per unit of fuel input) than the existing facility, it would produce greater total emissions. These higher emissions at the Northport site, though, would be offset by reduced emissions at other locations or by reductions in purchased power in the various energy markets. System wide emission benefits, however, can also be obtained in numerous alternate ways that do not require repowering Northport.

5.3.5 Environmental Benefits of New Units

A repowering of Northport would essentially replace the existing combined generating capacity of the four existing steam units with cleaner burning, state-of-the-art gas turbine technology and batteries. The benefits of repowering include:

- The replacement of older power generation with start-of-the-art combustion turbine technology in a combined and simple cycle configuration that achieves a very high fuel efficiency resulting in less fuel usage per unit of generation.
- The reduction in the rate of air emissions per MWh of energy produced through use of advanced emissions control technology and natural gas as a primary fuel.
- Eliminates the use of a ‘once-through’ cooling system at the existing plant.

- Avoids major upgrades to the electrical transmission system.
- Modernizes an existing generating facility with the most efficient technology – given the site's constraints.
- Flexible operation for load following intermittent renewable energy resources.

5.4 CONSTRUCTABILITY

The layout of existing plant equipment and available site acreage presents several challenges for repowering Northport. While the area available for new construction is sufficient to complete installation of the new power blocks, it is inadequate to house all contractor laydown, craft parking, staging and contractor trailers within proximity to the new power block. Therefore, open spaces around the Northport facility would need to be utilized to the extent possible to support construction. By using these spaces to support the contractor's construction, careful coordination for delivery of equipment/materials and coordination between the contractor and Grid's operating staff will be required. This will also impact the contractor's productivity. Phases 1 and 3 construction activities will also be impacted due to the limited mobility around the existing units that are bound to the east by the PSEG LI substation with overhead connections and the Northport inlet road to the west. The contractor may need to consider barge delivery and off-loading for major equipment. This may require improvements to the dock area to accept large barge deliveries.

An additional challenge is that demolition of Units 1 and 2 and construction of the Phase 3 simple cycle unit would need to take place directly adjacent to the Phase 1 and Phase 2 power blocks. These units must be available to operate throughout the course of demolition and construction. It is likely that barriers will need to be constructed to isolate and protect the units and construction activities, and such barriers and associated construction activities will have to be scheduled during non-operating periods.

It will be imperative for the contractor to develop a construction plan and schedule that sequences the installation of major equipment in a manner that avoids costly delays due to the limitations of crane access at the site. The use of off-site modular construction, particularly regarding the heat recovery steam generator (HRSG) and air-cooled condenser (ACC), is recommended and would be beneficial to both reducing the amount of on-site labor activities as well as the number of large crane picks.

Based on an earlier assessment, there is likely a need to limit the impact of noise on the surrounding community. To address noise concerns, enhanced sound attenuating features will likely be required from original equipment manufacturer (OEM) suppliers for the major noise generating equipment. This includes items such as enclosures for the unit's Boiler Feed Pumps, sound isolating panels atop the HRSG and elsewhere where engineering judgement determined a need, low noise fans and sound attenuating louvers at selected areas of the ACC, and air inlet and stack silencers. Allowances in the project cost were made for noise mitigation based upon best engineering judgment should future sound modeling surveys determine their need.

5.4.1 Demolition

Demolition will include decommissioning and demolition of all four steam units, fuel oil tanks, and the administration building. The small 16 MW simple cycle combustion turbine unit on the site will remain. Appropriate demolition means and methods will consider impacts to the operating units, the environment, and the community.

5.4.2 Equipment Delivery

Access to the site for the delivery of equipment is adequate. The site can be accessed by means of two roads. The primary access is off Fort Solonga (Route 25A) onto Waterside Avenue. Waterside Avenue is a narrow, two-way road with residences on both sides, narrowing as it approaches the Northport site. A second means of entry to the site is through the Northport boat ramp area. A pathway east of the Northport soccer park leads directly into the Tank Farm area of the existing site. Delivery is also possible by barge into the Northport inlet road and offloaded directly into the construction areas for the Phases 1 and 3 combined cycle power blocks. It is likely that larger equipment and construction equipment may need to be delivered via barge due to the limited width and height along the east and west sides of the existing units.

5.5 STORM PROTECTION

Northport is, for the most part, outside the 0.2% (1 in 500 year) annual chance floodplain. Superstorm Sandy demonstrated the ability of the current plant to handle heavy storm conditions. The main plant was generally unaffected by that storm, both due to its design features as well as compensatory operational measures, such as closing and sealing external doors, placing protective sandbags around motor control centers and other sensitive equipment, etc. Therefore, extraordinary grade modifications or storm hardening provisions were not addressed as part of the study.

5.6 PROJECT SCHEDULE

A summary level project phasing schedule, shown in Appendix D, was developed for the proposed Northport repowering (i.e., Scenario 3) to indicate the required construction and demolition timing for each phase. The schedule, as previously noted, is comprised of three phases and is laid out over a 13.5-year schedule.

Phase 1 provides for a 2-year period to complete the Article 10 process for Phase 1. Following receipt of required permits, existing fuel oil tanks 2 & 3 would be demolished to create laydown space to support construction. The execution phase of the construction is scheduled for 3 years starting with the completion of the Article 10 and air permitting processes. The construction of the battery energy storage system (BESS) would commence approximately one (1) year after the start of the Combined Cycle (CC) and be completed such that it can be commissioned along with the CC plant.

The Phase 2 Article 10 and air permitting commences in Year 2, with a 2-year time frame to complete. Similar to Phase 1, the permitting process is followed by a 3-year execution phase for the Phase 2 Simple Cycle (SC) units. Total construction time will likely require less than 3 years to complete; however, additional time was allotted to account for existing facilities that must be relocated or demolished prior to starting construction of the SC units. Following the completion of Phase 2 construction, existing Units 1 & 2 can be demolished, which is anticipated to require 2 years to complete.

Due to this schedule constraint under Phase 2, the Phase 3 Article 10 and air permitting processes for the new CC and SC units does not commence until after the completion of Phase 2 construction and coincides with the Units 1 and 2 demolition efforts. The Phase 3 CC and SC construction commences in Year 9 following the demolition of Units 1 and 2 and related Phase 3 permitting. Construction execution is scheduled for a 3-year period. The Phase 3 BESS construction, however, cannot begin until the existing fuel oil tanks supporting Unit 3 and Unit 4 operation are demolished, which cannot take place until after these units are officially shuttered. Therefore, Phase 3's Article 10 process for the BESS is scheduled to begin in Year 11, with BESS construction complete in the middle of Year 14.

LAST PAGE OF CHAPTER 5.

6. REPOWERING PROVISIONS AND ECONOMIC VIABILITY

The purpose of this chapter of the report is twofold:

- To set forth and address the Ramp Down and Repowering provisions, specifically Articles 10 and 11 of the PSA; and
- To present and discuss the results of the economic analyses associated with each Scenario relative to the Reference Case, specifically the increase in total costs attributable to repowering and the associated impacts on the cost of electricity to customers.

6.1 RAMP DOWN AND REPOWERING PROVISIONS

Under Article 10 of the PSA, LIPA has the contractual right to reduce (Ramp Down) all or any portion of the Northport generating unit capacity at the site[14] that it is obligated to purchase from Grid. The exercise of the Ramp Down provision is subject to the following conditions:

- Prior written notice: LIPA must provide 2-years notice for steam units and a 1-year notice for all other units prior to the Ramp Down Effective Date.[15]
- Payment: LIPA is obligated to make a Ramp Down payment upon the effective date of the Ramp Down, which payment is equal to:
  - The net book value of the ramped down unit(s) as of the Ramp Down Effective Date, less
  - Any applicable discounts per Appendix G of the PSA, plus
  - For the steam units, an amount equal to 18 months of operating and maintenance expenses (both allocated and direct) and 12 months of operating and maintenance expenses in the case of non-steam units, less
  - The notional account[16] (Tracking Account) up to the lesser of the Ramp Down payment or the amount in the Tracking Account.
- Retirement Eligible: The unit(s) to be ramped down are found to be able to be retired from a reliability perspective.

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14 Northport Steam Units 1, 2, 3 and 4, and the 16 MW simple cycle gas turbine.

15 The earliest Ramp Down Effective Date of any or all of the Northport steam generating units is May 1, 2021.

16 The amount in the Tracking Account is equal to the Net Book Value of Northport 1 as of May 31, 2013.

- Property Taxes: For a steam unit, LIPA is responsible for reimbursement of the property taxes paid by Grid for the remainder of the Calendar Year in which the Ramp Down Effective Date occurs and for the three (3) succeeding Calendar Years thereafter or until the end of the term of the PSA, whichever occurs first.[17]

Upon the effective date of the Ramp Down, LIPA has no further right or obligation to purchase or pay for the capacity and associated costs of the ramped down unit(s) and the capacity and other charges under the PSA will be reduced accordingly. Grid, upon receipt of the Ramp Down notice, must, within 90 days, advise LIPA whether Grid will either continue to operate the ramped down unit(s) or shut down and mothball or demolish the unit(s).

Article 11 of the PSA provides LIPA an option to direct Grid to, among other things, repower any or all of the Northport units. Repowering is defined as: ". . . replacing part or all of each generating unit . . . with new generating equipment or entire units." In the event this option is exercised, LIPA is obligated to make certain one-time payments (Repowering Payment) associated with the unit(s) that is being taken out of service for purposes of the repowering. Such payments include:

- The net book value of the unit that is being repowered as of the date the unit is taken out of service;
- Less the applicable discount as provided in Appendix G (of the PSA);
- Less the notional account (Tracking Account) up to the lesser of the Repowering Payment or the amount in the Tracking Account.

LIPA is also responsible for the costs associated with demolition and site remediation. Such cost, including a return, would be recovered over the term of the new unit's PPA or, at LIPA's option, in one lump sum.

LIPA's payments under the PSA would be reduced to reflect the Northport unit(s) removed from service due to the repowering. The reduction in the payments under the PSA would include costs associated with return and depreciation, and direct and indirect O&M. Additionally, per the provisions of Article 11, for each repowered unit, LIPA and Grid would enter into a mutually acceptable Purchase Power Agreement (PPA) under which LIPA would agree to purchase the repowered unit's capacity, energy, and ancillary services.

[17] Assumes the unit(s) are ramped down and retired.

For purposes of this analysis, it was assumed that LIPA would exercise its rights under the Repowering Option and direct Grid to repower the Northport facility. LIPA and Grid would enter into a mutually acceptable long-term purchase power tolling[18] agreement for each of the repowered units with Grid retaining ownership of the site. It was also assumed that there would be no change in the level of annual property taxes, *i.e.* the annual property taxes associated with the repowered units would be the same as the amounts that are projected to be paid in the absence of repowering. LIPA has certain rights under both the PSA and, separately, under Schedule F of the Merger Agreement, to purchase the ramped down generating facility, including the related site and all Regulatory Rights. These purchase rights are addressed in detail in Section 6.3, below.

6.2 ECONOMIC ANALYSIS

The costs and benefits of repowering Northport are reflected in the results of the Production Cost modeling[19] and Financial Model runs. The Financial Model is a comprehensive representation of LIPA's annual revenue requirement based upon LIPA's financial objectives. Essentially, the Financial Model captures all projected annual expenses and revenue and produces a pro forma financial statement by year for each year of the Study Period, 2020 - 2040.

6.2.1 Modeling Considerations

As noted, elements of the Financial Model include all costs expected to be incurred each year, including, but not limited to, those associated with the following:

- Total fuel and purchased power costs (Production Cost Model)
- Electric transmission and distribution capital expenditures, including those, if any, required due to repowering. (There were no repowering related electric transmission and distribution expenditures assumed in the Study.)
- Payments LIPA makes for Power Purchase Agreements (PPA), including the PSA
- Operating Services Agreement (OSA) charges
- Property taxes (PILOTs)
- Debt service

[18] LIPA would be responsible for the procurement and delivery of gas and oil for the combined cycle and simple cycle units; and for electricity for the batteries.

[19] The key tools used to assess production cost, emissions and capacity impacts are described in Appendix E - Production Cost Methodology, and Appendix F - Market Forecasting Methodology.

- Satisfaction of LIPA's coverage ratio targets
- LIPA's 18% ownership of Nine Mile Point 2

As further described below, there are two main categories of costs and impacts associated with a ramp down or repowering of a generating unit:

- Production costs, e.g., fuel and variable O&M
- Fixed cost, e.g., the reduction in the PSA Capacity Charge and the PPA cost of the repowered unit

Production Costs and Financial Model runs were made for Grid's Northport repowering proposal (Scenario 3)[20], which include the phased installation of two 340 MW CC units, three 230 MW SC units, and three 50 MW BESS units. Grid's proposal assumes that the design, permitting, and construction of the new units would occur on the Northport site over a period of approximately fourteen years. Specifically, Grid's proposal targeted replacing each existing unit in a phased approach where a new unit is built in an open area of the site, its electric output tied into the substation bay of the unit it is replacing, and the existing unit then decommissioned and demolished creating space for future phases of the repowering, while the remaining existing units continued to operate. A timeline of the commercial operation dates (COD) of the "new" units and the retirement/demolition of the existing units is shown in Appendix D. In addition to analyzing Grid's repowering proposal, Production Cost and Financial Model runs were made for the five other scenarios described in Section 4.2, Scenarios, of this report.

Economically, Grid proposed that LIPA enter into a long-term PPA for each of the repowered units, which contained the following major provisions:

- A 20-year term
- A constant (flat) annual capacity payment
- A Fixed O&M payment with a fixed annual escalation rate (2% for CC and SC units and 1.5% for BESS)
- Variable O&M $/MWH charges
- PILOT's to be paid by LIPA
- The costs associated with the demolition of the existing Northport units
- LIPA would be responsible for fuel (gas and oil) procurement including delivery to the plant

[20] Presented as Scenario 3 in Chapter 4, and further descripted in Chapter 5.

For illustration purposes, Table 6.1 shows the cost impact in a typical year of exercising the Repowering Option for one Northport steam unit using a similar sized gas fired combined cycle unit (Scenario 1) relative to the Reference Case.

Table 6-1: Northport Unit Repowering Cost Impact in 2030

Cost Type	Cost	$M
Fixed Costs	CC PPA	$116
	PSA Capacity Charge	($45)
CC Production Costs Savings	Fuel & Purchased Power	($7)
Net Cost Increase		**$64**

As can be seen, the fixed costs associated with the CC PPA significantly exceeds the reduction in the PSA Capacity Charge. Although the repowered unit results in a reduction in system production costs (fuel and purchased power), this reduction is not nearly sufficient to offset the overall increase in fixed costs. Several factors contribute to the modest reduction in production costs, including relatively low projected gas prices and the significant addition of renewable energy (OSW) being injected into Long Island, which tends to suppress the market price of energy as well as the amount of time the CC operates at full load.

6.2.2 Summary of Results

The impact (cost increase or decrease) on LIPA, and correspondingly its customers, associated with Grid's Northport repowering proposal (Scenario 3), as well as the other five (5) scenarios evaluated, was measured as the difference between two Financial Model runs covering a 20-year Study Period, 2020 – 2040.

- A common Reference Case based upon the following: the currently approved load and energy forecast; the retention of the existing on-island power supply portfolio; the implementation of various initiatives to help satisfy the goals set forth in NY State's CLCPA; the cables (Neptune and Cross Sound Cable) remaining in-service; and, the satisfaction of local and statewide reliability obligations.[21]

[21] The LI Locational Capacity Requirement (LCR) and the Statewide Installed Reserve Margin (IRM).

- The Reference Case 'but for' the assumed Scenario.

In terms of the financial and cost impacts of each Scenario, two approaches were considered. The first approach was to assume the PPA pricing as proposed by Grid for each of the repowered units, which pricing was based on a 20-year term starting from the point in time at which each new unit goes into commercial operation, even though such pricing would extend beyond the Study Period end date of 2040. The second approach was to assume that for any given scenario that the costs associated with conventional generation would be recovered on an accelerated basis, (i.e., by the beginning of 2040 when the CLCPA requires 100% carbon free emissions from electric generation) to reflect the likelihood that such projects would then be forced to retire. Table 6-2, below, provides a summary of the total increased costs customer bill impacts of each Scenario under both approaches when compared to the Refence Case. Positive numbers reflect increased costs to LIPA and its customers and negative numbers reflect decreased costs. Results for Scenario 6 are based upon a proportionate reduction (~25%) in Northport property taxes due to the ramp down and retirement of one unit at Northport. The exact value of a reduction in property taxes is uncertain. However, even assuming that there was no reduction in property taxes, LIPA's costs would still be lower, albeit to a lesser degree, e.g., a reduction of $68 million as opposed to the $303 million shown in Table 6-2.

Table 6-2: Increased Costs thru the Study Period (2020 - 2040)

Total Incremental Costs (NPV: $millions)						
	Scenario					
PPA Type	1	2	3	4	5	6**
20-Year	$682	$1,704	**$1,616**	$1,220	$1,569	($303)
Full Recovery by 2040*	$770	$1,982	**$2,081**	$1,470	$1,948	($303)

Total Incremental Residential Bill Costs ($)						
	Scenario					
PPA Type	1	2	3	4	5	6**
20-Year	$597	$1,565	**$1,480**	$1,092	$1,436	($263)

Full Recovery by 2040*	$663	$1,794	**$1,894**	$1,301	$1,768	($263)

* Only for technologies using fossil fuel.
** Unit 1 retirement only. There is no associated PPA with Scenario 6. Results are based upon a reduction of approximately 25% in Northport property taxes

Both the net present value of increased costs and the increase in the total bill of an average residential customer are significant assuming a 20-year PPA for Scenarios 1 – 5, and even greater when considering full cost recovery by 2040. Scenario 6, retirement of Northport Unit 1 only (i.e., no associated PPA) shows a reduction for both total costs and in total costs for a typical residential bill.

6.2.3 Results for Grid Proposal (Scenario 3)

In viewing the results of Scenario 3 (i.e., Grid's proposal) and assuming a 20-year PPA, Figure 6-1 shows an increase in LIPA's total annual costs in each full year for the period 2026 - 2040.

Figure 6-1: Increase in Annual Costs: Scenario 3

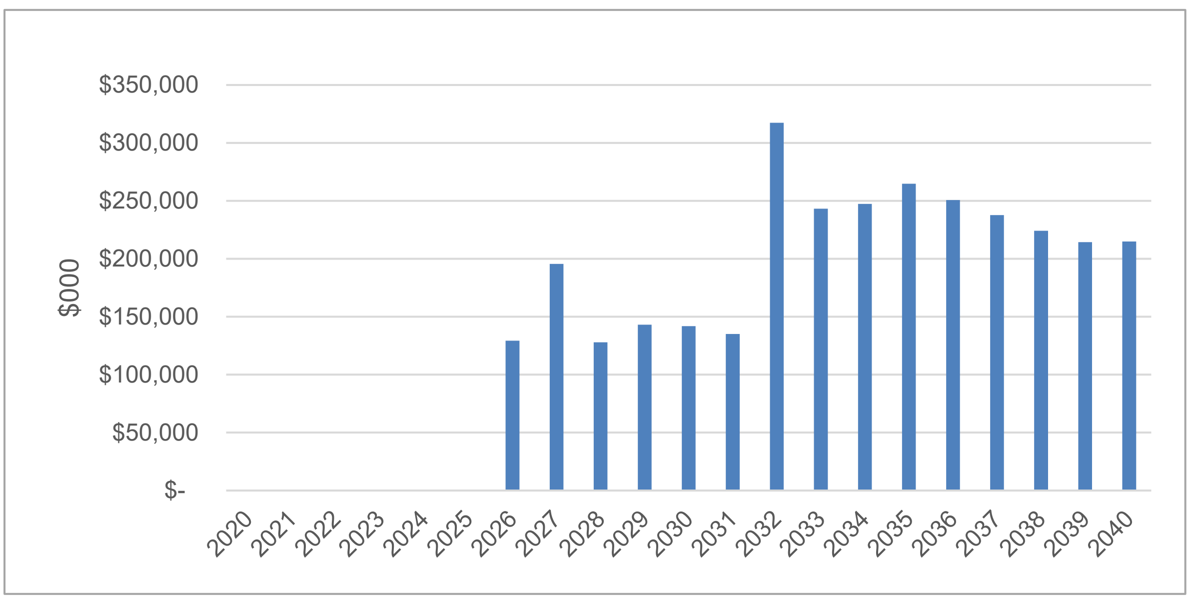
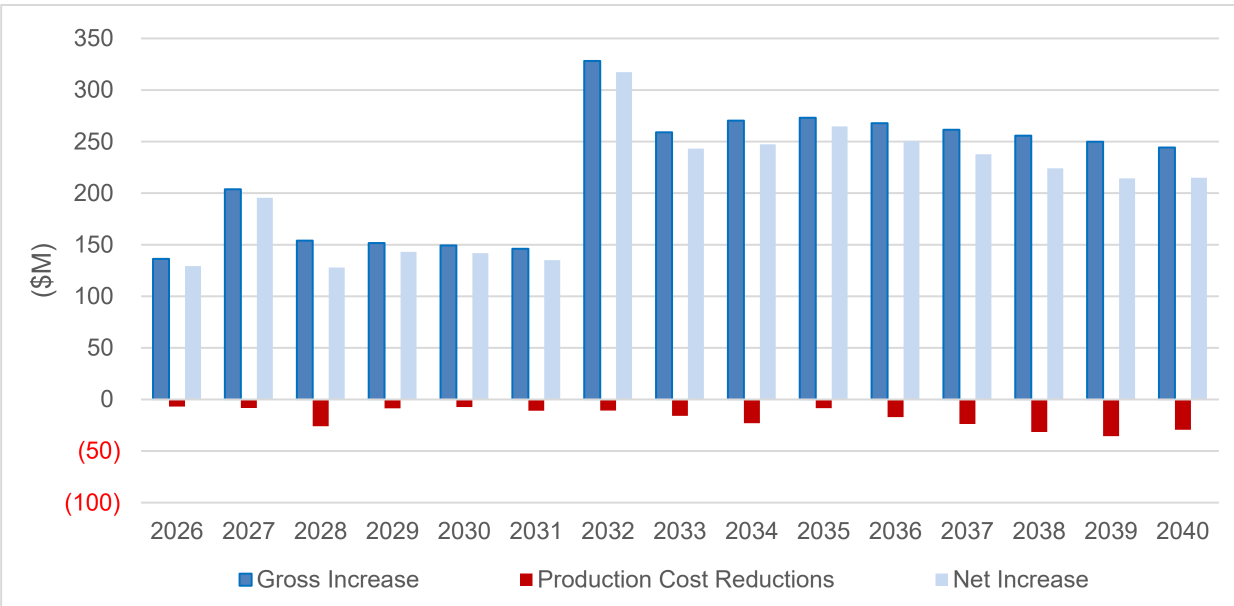


Figure 6-2 shows the composition of the increases depicted in Figure 6-1. Specifically, the reduction in production costs (fuel and purchased power) attributable to the more thermally efficient repowered units, along with the decrease in the PSA Annual Capacity Charge resulting from the retirement of the existing Northport units, is not sufficient to offset the higher PPA fixed costs associated with the repowered units. As measured over the first full

10 years (2026 – 2035), the total additional cost ($ nominal) to LIPA's customers is $1.945 billion, and over the course of the Study Period (thru 2040), the total additional costs to LIPA's customers is $3.088 billion.

Figure 6-2: Composition of Increase in Annual Costs: Scenario 3

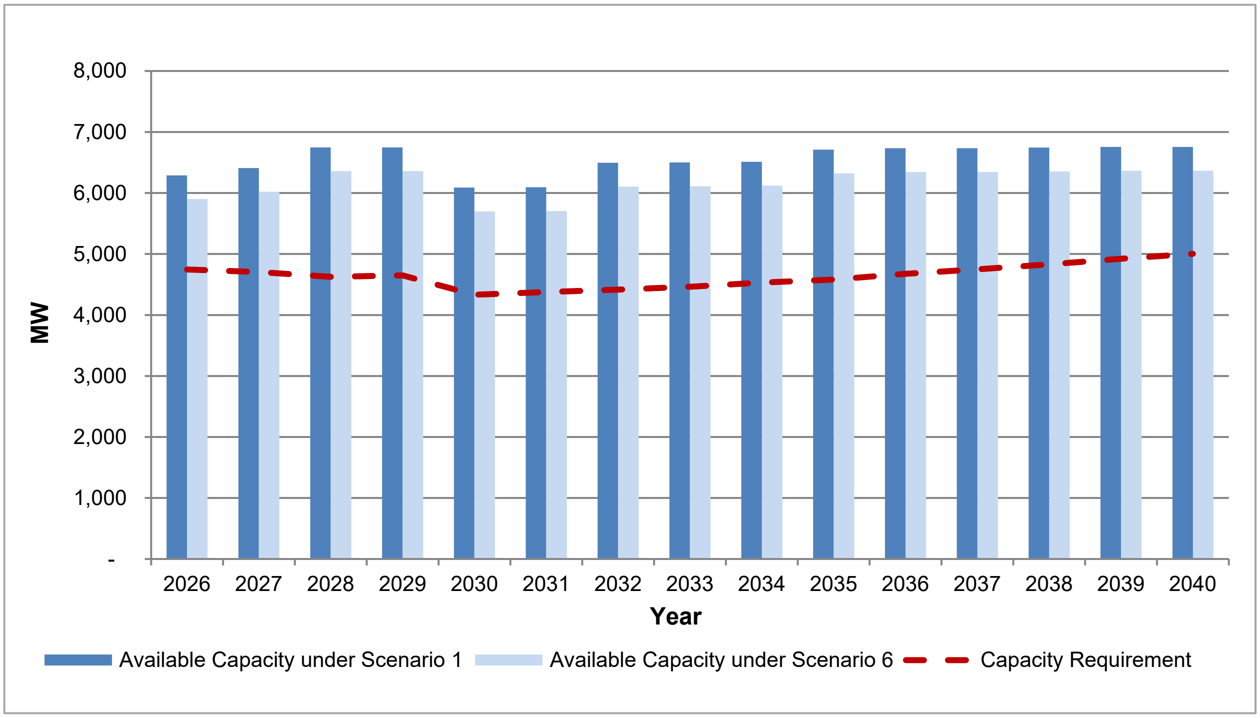


Grid's Northport repowering proposal (i.e., Scenario 3) results in increases in residential customers' bills. As measured over the first full 10 years (2026 – 2035), the total additional cost ($ nominal) to an average residential customer is $985, and over the course of the Study Period (thru 2040) the total additional cost to an average residential customer is $1,480, assuming a 20-year PPA. If the total costs of each PPA were to be recovered by 2040, the increase to the average residential customer would be $1,894.

6.2.4 Results for Repowering or Retirement of a Single Unit (Scenarios 1 and 6)

As shown in Table 6-2, ramping down and retiring a Northport steam unit (Scenario 6) results in a net present value reduction in total costs of $303 million (assuming an approximate 25% reduction in property taxes) as compared to not ramping down a unit. Conversely, repowering a unit at Northport (Scenario 1) results in an increase in total costs of $682 million assuming a 20-year PPA and an increase of $770 million assuming the cost of the repowered unit would be recovered by 2040. As demonstrated in Figure 6-3, reliability criteria are satisfied under either scenario. In fact, there remains a considerable amount of excess on-island capacity even if a Northport unit is ramped down and retired.

Figure 6-3: Capacity Excess Under Scenarios 1 and 6*



LI Locational Capacity Excess (MW)															
Year	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Scenario 1	1,544	1,706	2,123	2,098	1,756	1,719	2,079	2,037	1,981	2,132	2,058	1,985	1,914	1,833	1,751
Scenario 6	1,154	1,316	1,733	1,708	1,366	1,329	1,689	1,647	1,591	1,742	1,668	1,595	1,524	1,443	1,361

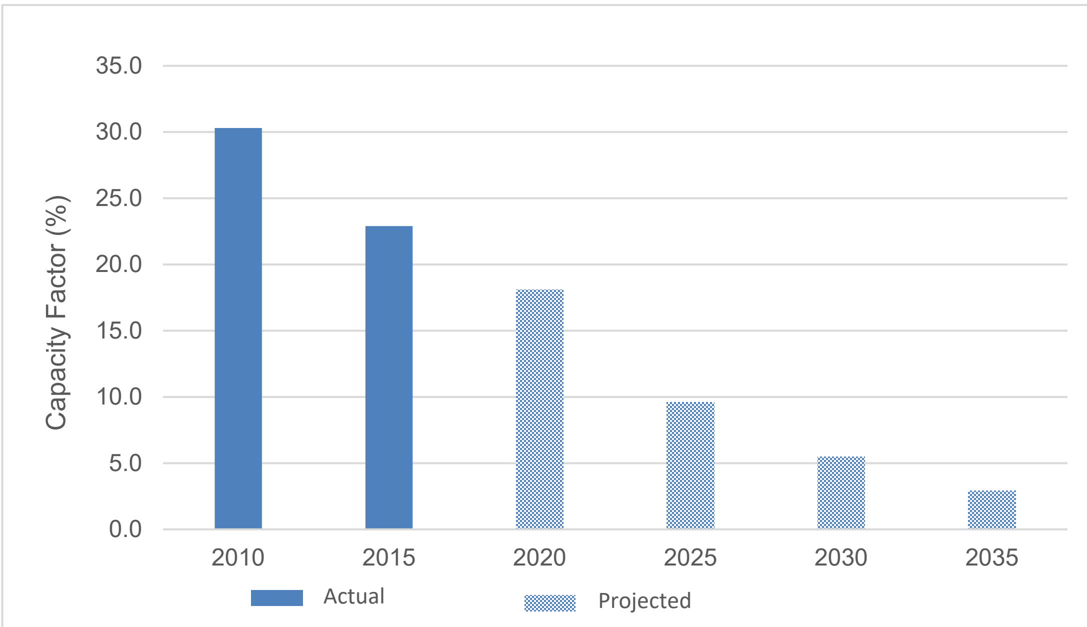
*For the purpose of the economic analysis, it was assumed that the terms and conditions of the PSA would extend through 2040.

The Northport power station has become increasingly less competitive in the energy market in recent years as manifested by a steady decline in the steam units' average capacity factor (see Figure 6-4).[22] As shown, the annual capacity factor declined from 30.3% in 2010 to 22.9% in 2015 and is projected to decline to 2.9% by 2035. The station, though, is highly reliable as measured by its availability to operate, particularly during the critical summer months, June through August. In the summer periods from 2014 – 2019, the units were available to generate energy an average of over 96% of the time, significantly above a peer group average of about 88%. In summary,

[22] Values for 2010 and 2015 are actuals and values for 2020 – 2035 are projected.

the existing Northport units are expected to remain useful for their ability to serve as reliable standby units, and there is no compelling reason to repower the units for heavier use.

Figure 6-4: Northport Capacity Factor Trend



As noted previously, capacity factor is a measure of a generating unit's energy output and, therefore total emissions, since emissions are directly related to energy output. Consequently, emissions at Northport have declined significantly and will continue to decline over time due to changing system conditions brought on by, among other factors, energy efficiency programs, the introduction of increasing levels of renewable energy, *e.g.* Orsted's (formerly Deepwater Wind) offshore wind farm, and, more significantly, the implementation of various initiatives designed to achieve the mandates set forth in the CLCPA.

6.3 SITE ACQUISITION OPTIONS

LIPA has certain site acquisition rights under Article 10 of the PSA and, separately, under Schedule F, Grant of Future Rights to the Merger Agreement. The exercise of either of these site acquisition options would give LIPA the ability to select and contract with a party other than Grid to build, own and operate generating units on the acquired site. The following is a brief description of LIPA's rights under each option.

6.3.1 PSA Article 10 Capacity Ramp Down

In the event LIPA choses to ramp down all or any portion of a generating facility's capacity during the term of the PSA (ending April 30, 2028) and Grid notifies LIPA that, pursuant to Section 10.2.2, it will shut down and mothball or demolish the generating facility as of the effective date of the ramp down, LIPA has the right to purchase the generating facility including the related site.[23] If LIPA exercises its purchase option under Section 10.2.2 of the PSA, or its right to purchase the site under Schedule F, as discussed below, LIPA has the right to elect to contract with a third party, or Grid, to repower or construct new generation on the site. However, regarding the repowering of the four (4) Northport steam units, if LIPA wishes to initiate a repowering within a three-year period commencing with the Ramp Down Effective Date, the procedures set forth in Article 11 of the PSA must be employed.

6.3.2 Schedule F – Grant of Future Rights

Under Schedule F, LIPA has the right to lease or purchase parcels of land at any of the generating facility sites of Grid for the purpose of constructing new electric generating facilities to be owned by LIPA or its designee, provided such lease or purchase does not materially interfere with either the physical operation of any generating facility or environmental compliance. In the event of interference, LIPA must provide compensation. The lease or purchase price will include the fair market value at the time of lease or purchase as determined by a jointly selected independent real estate appraiser. Of note, the Northport site is not believed to have sufficient available land to develop new generation on the site separate from the existing units.

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[23] Per the PSA, "Generating Facility Site" means each parcel of land upon which the generating facility is situated together with land contiguous thereto owned by Grid.

7. IMPACT ON THE COMMUNITY

7.1 JOBS

The most significant impact on jobs is expected during the construction period. Grid's three-phase Northport repowering proposal (Scenario 3), while extending over almost 14 years in total, includes approximately eight years of construction activity. The total number of construction jobs created during the construction period is estimated to be 440 jobs in Phase 1, 240 jobs in Phase 2, and 590 jobs in Phase 3. The peak construction period is expected to be in the first half of 2025 during which nearly 680 jobs would be created. Table 7-1 below provides a summary of the estimated peak number of construction jobs that would be created during each phase of the Northport repowering.

Table 7-1: Peak Construction Jobs Creation: Scenario 3

Repowering Phase	New Units	In-Service Date	Construction Period	Peak Number of Jobs
Phase I	1x1 CC	January 1, 2026	2023 - 2025	440
	1 BESS	May 1, 2025		
Phase 2	2x0 SC	January 1, 2027	2024 - 2026	240
	1 BESS	May 1, 2025		
Phase 3	1x1 CC	January 1, 2032	2029 – 2031, and 2033 - 2034	590
	1x0 SC	January 1, 2032		
	1 BESS	May 1, 2034		
		Total	**8 Years**	**1,270**

In addition, it is estimated that there would be approximately 50 – 60 full time positions created related to operations and maintenance once the new units were placed in-service. Finally, there would also be positive direct and indirect effects on the local economy during the construction period, but those effects have not been studied.

7.2 TAXES

A significant economic disincentive to repowering Northport is the level of taxes that the community of Huntington levies against the plant. LIPA has identified the significant, disproportionate, and burdensome effect

of taxes on LIPA's customers. Notably, taxes paid by LIPA, in all their forms (PILOTs, fees, etc.), totaled over $680 million in 2019, representing approximately 15 percent of a customer's monthly bill, or 3 times the national average. LIPA's tax payments in 2020 for four major power stations, owned by Grid, will be $184 million: $86.1 million a year for Northport, $43.2 million for the Barrett plant, $30.8 million for Port Jefferson and $23.9 million for the Glenwood Landing property, which no longer houses a steam plant. It is interesting to note that taxes paid on those four facilities in 1999 totaled slightly over $116 million. So, in 21 years, taxes on those plants have risen almost 59 percent while use of the plants continues to decline. Not surprisingly, LIPA has been seeking a tax reduction since 2010.

LIPA's efforts to reduce the property taxes at the plants have begun to bear fruit. In December 2018, LIPA and the Town of Brookhaven and the Village of Port Jefferson reached agreements on deals that will, among other provisions, reduce LIPA's tax bill for the Port Jefferson power station by approximately 50 percent over a phase-down period starting in 2019. The move would reduce the $32.6 million LIPA paid in annual taxes in 2018 for the plant to just over $16.8 million by 2026. LIPA also reached a tentative agreement with Nassau County in November 2019 to reduce taxes on the Barrett and Glenwood plants under terms similar to those for Port Jefferson. Regarding Northport, court proceedings between LIPA and the Town of Huntington to resolve the issue have concluded and while no decision has been rendered as yet by the court, LIPA and the Town are in discussions about a potential settlement. Should no settlement be reached, a court decision is expected in 2020.

While taxes should be paid by electric customers to locales hosting power plants, the tax burden should be both equitable and reasonable. LIPA continues to strive to achieve that balance for the benefit of its customers.

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8. CONCLUSION

The Study evaluated the engineering, environmental permitting, and cost feasibility of repowering the Northport power plant. Grid's repowering proposal (i.e., Scenario 3) is based on a multi-year, multi-phase approach that includes gas-fired combined cycle and simple cycle units, and bulk energy storage batteries. It does not include on-site renewable resources. Additional scenarios, though, included other technologies such as offshore wind and a cable upgrade.

Based on the Study's analysis, the following conclusions were reached:

- Given the overall outlook for Long Island that shows a current surplus of installed generating capacity that is expected to grow as new, clean renewable resources are added in response to state policy and legislation, combined with load growth that is expected to decline until 2028 and then increase only gradually thereafter, there will be less room in LIPA's supply portfolio for conventional gas-fired generation, whether it's the current fleet of LILCO-era generating units or new repowered units. Increasingly, over time, the older conventional units will be excess to LIPA's resource needs and strong candidates for retirement. Already LIPA has announced plans to retire in 2020 and 2021 two of the older peaking units contracted under the PSA, with more such announcements to come in the future pending the results of further planning studies.
- Grid has proposed a repowering configuration that has certain environmental benefits (i.e., lower rate of emissions) and better operational characteristics (lower heat rate and, therefore, more efficient) compared to the existing Northport plant. However, since all conventional gas-fired generation in the state is gradually being phased out by 2040 per the goals established in the CLCPA, the emissions benefits of a conventional repowering likewise would fade away by 2040.
- Grid's repowering proposal is technically feasible, i.e., the repowered plant can be constructed and operated as proposed by Grid. This also means the repowered plant can obtain the necessary permits to construct and operate the plant based on known environmental requirements and expected changes. However, as further elaborated below, Grid's proposal would increase costs to ratepayers and is not in ratepayers' interests.
- The existing Northport plant can be expected to continue operating reliably through the end of the Study Period.

- Along with Grid's proposal, an additional five (5) scenarios were evaluated to form a more robust understanding of the costs of repowered plant configurations. The key conclusions are as follows:
    - There is no scenario, including Grid's proposal, which includes the construction of new conventional natural gas-fired generating capacity and/or batteries, under which the reduction in production costs (fuel and purchased power) associated with the repowered plant, plus the decrease in the PSA Annual Capacity Charge resulting from the retirement of the existing Northport units, are sufficient to offset the higher PPA fixed costs associated with the repowered units. This result is consistent whether the economic analysis assumes 20-year PPAs for conventional gas-fired units, which would expire post the 2040 CLCPA mandate for 100% carbon free electricity generation, or that the costs of conventional units are fully recovered by 2040.
    - Grid's repowering proposal would result in an approximate total net present value cost to LIPA's customers of between $1.6 billion and $2.1 billion, or about $1,500 to $1,900 (nominal dollars) per customer over the Study Period, dependent upon the type of PPA assumed.
    - Scenario 6, representing retirement (not a repowering) of a steam unit, results in reduced costs of approximately $300 million[24] (net present value) and retirement of a unit still allows for local and system reliability standards to be met.

LIPA has made no decision as yet regarding the retirement of additional steam plants (Northport, Barrett or Port Jefferson) beyond those (Far Rockaway and Glenwood) that were retired in 2013. However, it is likely that results of analyses conducted during 2020 will indicate additional closures, as early as 2022 – 2023. Consequently, the retirement of one or more of the steam units at Northport is more likely in the coming years than a repowering of the plant as long as the impacts on the reliability of power supply both for Long Island overall and for the local area served by the plant remain within acceptable criteria. Such a decision would be consistent with LIPA's more recent decision to retire two gas turbine units in 2020 and 2021.

There are many variables (such as the CLCPA) under development and/or in implementation that create uncertainty regarding the optimal characteristics and configuration of a repowering that might impact the Study's

[24] This assumes a savings of approximately 25% of current property taxes. However, even assuming no change in property tax levels, it is still economic to retire at least one Northport unit.

conclusions. Many of these uncertainties are expected to be clarified with time. In fact, the changing market and regulatory conditions will be evaluated in detail in LIPA's next Integrated Resource Plan (IRP), scheduled to begin in 2020. Results of the IRP will provide a roadmap for decisions regarding the deployment of new, clean energy on Long Island and the disposition of existing capacity. However, none of the repowering configurations examined in this Study - except a unit retirement - are in the best economic interests of LIPA's customers and a repowering of Northport should be, if not abandoned, at least deferred, as there is no current economic or reliability basis for proceeding.

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9. ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
Barrett	The E.F. Barrett Power Station, located in the Town of Hempstead in the County of Nassau, New York
BESS	Battery Energy Storage System
Bill	The New York State Senate – Assembly January 15, 2015 Senate Bill 2008-B and Assembly Bill 3008-B
Board	Long Island Power Authority Board of Trustees
BOP	Balance of Plant: Includes Structures, Systems, and Components of a facility
CC	Combined Cycle: A power generating unit composed of a combustion turbine generator, a heat recovery steam generator, and a steam turbine generator
CES	Clean Energy Standard: A New York State PSC Order adopting the goal that 50% of New York's electricity is to be generated by renewable sources by 2030. The goal has now been increased to 70% by 2030 through the CLCPA.
CF	Capacity Factor
CLCPA	Climate Leadership and Community Protection Act: The CLCPA was signed into law in July 2019 and establishes various clean energy goals for New York State
COD	Commercial Operation Date
CT	Combustion Turbine
DMNC	Dependable Maximum Net Capacity
EAF	Equivalent Availability Factor
EFORd	Equivalent Forced Outage Rate-demand
GENCO	A legal entity of National Grid USA (in the context of this report, another term for National Grid) that operates the power generation assets in accordance with a Power Supply Agreement with LIPA
Grid	National Grid
Heat rate	A measure of an electric power plant's efficiency at converting fuel energy, measured in MMBtu, to electric power, measured in MWh.
LI	Long Island

Term	Definition or Clarification
LILCO	Long Island Lighting Company
LIPA	Long Island Power Authority: a publicly owned, not-for-profit electric utility chartered to supply electric power to Long Island and the Rockaways.
kW	Kilowatt: a unit of power generation capacity
kWh	Kilowatt hour; a unit of electric energy used to measure how much electricity is generated or used.
MMBtu	1,000,000 British thermal units; a unit of energy used to measure how much energy in fuel is available to be converted to electrical energy (see Heat Rate, above)
MW	Megawatt: A unit of power generation capacity. A megawatt is equivalent to 1,000 kWs
MWh	Megawatt hour: A unit of electric energy to used measure how much electricity is generated or used. A megawatt hour is equivalent to 1,000 kilowatt hours
National Grid	National Grid USA, the investor-owned energy company that owns and operates E.F. Barrett under a Power Supply Agreement (PSA) with LIPA.
NNC	Northport-Norwalk Cable: A submarine transmission cable across Long Island Sound to the Norwalk Harbor in Connecticut
Northport	The Northport Power Station
NP	Northport Power Station
NYSDEC	New York State Department of Environmental Conservation
NYSDPS	New York State Department of Public Service
NYISO	The New York Independent System Operator
NYSERDA	New York State Energy Research & Development
O&M	Operations & Maintenance
OSW	Offshore Wind
Port Jefferson	Port Jefferson Power Station
PPA	Power Purchase Agreement

Term	Definition or Clarification
PSA	Amended and Restated Power Supply Agreement dated October 12, 2012 and effective May 29, 2013, between LIPA and National Grid.
PSC	Public Service Commission
PSEG LI	PSEG Long Island: a subsidiary of Public Service Enterprise Group Incorporated (PSEG) that operates LIPA’s transmission and distribution system under a 12-year contract.
REV	Reforming the Energy Vision: A PSC policy framework to change the electric industry and ratemaking approach to capitalize on technology developments in conjunction with the SEP
SC	Simple Cycle: A power generating unit composed of a combustion turbine
SPDES	State Pollutant Discharge Elimination System
SEP	State Energy Plan: intended to coordinate all State agencies’ efforts affecting energy policy to advance the REV agenda.
STG	Steam Turbine Generator
UCAP	Unforced Capacity
ULSD	Ultra-Low Sulfur Distillate fuel

LAST PAGE OF ACRONYMS AND ABBREVIATIONS.

Appendix A: Benchmarking - Annual

Sargent&Lundy **Report # 17**

Benchmark Report - Annual

Created by: L. Bledin **Date Created:** 2/06/2020 **Printed:** 2/06/2020

Containing 29 Units in 20 Utilities 120.25 Unit Years

Matching the following criteria:

Unit Selection	All Units Incl Own
Unit Type	Fossil-Steam
Date Range	2014 to 2019
Periods	01 to 12
Commercial Date	1/01/1965 to 12/31/1980
MW Rating	325 to 425
1st Fuel Type	Gas(GG)

All values in this batch are Time-Based and are not weighted.

The following reports are included in this batch:

Annual Unit Performance

Annual Unit Statistics

Units Included in Study

Current Criteria

The following units are included in this batch:

NORTHPORT #1	NORTHPORT #2	NORTHPORT #3	NORTHPORT #4
EDDYSTONE #3	EDDYSTONE #4	HERBERT WAGNER #4	TURKEY POINT #1
YATES 6	YATES 7	TECHE #3	GORDON EVANS #2
LITTLE GYPSY #2	HORSESHOE LAKE #8	KNOX LEE #5	WILKES #2
WILKES #3	DECKER #2	DAVIS #1	LAKE HUBBARD #1
GREENS BAYOU #5	SIM GIDEON #3	V. H. BRAUNIG #3	O.W. SOMMERS #1
O.W. SOMMERS #2	GRAHAM #2	VALLEY #3	CHEROKEE #4
EL SEGUNDO #4			

Annual Unit Performance Report for Years 2014 - 2019, Periods 01 - 12

Sargent&Lundy

GADS Report (Based on IEEE Standard 762)

Report No.: 17
Printed: 2/06/2020
Unit Years: 120.25

Variable	Mean	Median	Minimum	Maximum	Range	Std. Dev.
Gross Maximum Capacity	386.99	392.00	324.17	434.06	109.89	30.18
Net Maximum Capacity	376.01	380.00	310.00	420.00	110.00	29.85
Gross Dependable Capacity	386.37	392.00	324.17	434.06	109.89	30.55
Net Dependable Capacity	375.40	380.00	310.00	420.00	110.00	30.20
Gross Actual Generation	308,745.00	239,727.00	0.00	1,204,443.00	1,204,443.00	295,370.38
Net Actual Generation	289,685.00	232,679.00	0.00	1,090,864.00	1,090,864.00	275,330.33
Period Hours	8,558.32	8,764.80	0.00	8,928.00	8,928.00	1,598.85
Unit Service Hours	1,953.90	1,822.32	0.00	5,622.91	5,622.91	1,400.14
Pumping Hours	0.00	0.00	0.00	0.00	0.00	0.00
Condensing Hours	0.00	0.00	0.00	0.00	0.00	0.00
Reserve Shutdown Hours	4,610.96	4,959.94	0.00	7,026.19	7,026.19	1,620.38
# of RSH Occurences	47.06	35.00	0.00	131.27	131.27	37.40
Total Available Hours	6,564.86	7,222.78	0.00	8,267.12	8,267.12	1,614.85
Forced Outage Hours	466.61	218.28	0.00	1,331.89	1,331.89	422.44
# of FOH Occurences	5.88	5.81	0.00	36.00	36.00	6.08
Planned Outage Hours & Ext.	1,161.22	981.44	0.00	2,485.23	2,485.23	758.29
# of POH Occurences	2.17	1.60	0.00	8.67	8.67	1.80
Maintenance Outage Hours & Ext	365.64	212.89	0.00	3,594.10	3,594.10	652.51
# of MOH Occurences	2.87	2.93	0.00	24.00	24.00	4.20
Total Unavailable Hours	1,993.46	1,488.83	0.00	4,755.42	4,755.42	1,042.15
# of FD Occurrences	15.86	7.00	0.00	76.80	76.80	22.07
Equiv. Scheduled Derated Hrs	15.60	5.91	0.00	115.58	115.58	23.42
Actual Units Starts	44.51	30.33	0.00	129.45	129.45	35.78
Attempted Unit Starts	45.18	30.33	0.00	129.82	129.82	35.69
Years in Service	44.78	44.00	39.00	51.00	12.00	3.17

Annual Unit Statistics for Years 2014 - 2019, Periods 01 - 12

Sargent&Lundy
GADS Report (Based on IEEE Standard 762)

Report No.: 17
Printed: 2/06/2020

Unit Years: 120.25

Variable	Mean	Median	Minimum	Maximum	Range	Std. Dev.
Planned Outage Factor	13.57	11.20	0.00	28.35	28.35	8.72
Unplanned Outage Factor	9.72	5.80	0.00	47.85	47.85	9.29
Forced Outage Factor	5.45	2.49	0.00	15.58	15.58	4.96
Maint. Outage Factor	4.27	2.43	0.00	41.01	41.01	7.43
Scheduled Outage Factor	17.84	14.06	0.00	47.41	47.41	10.41
Unavailability Factor	23.29	16.99	0.00	54.26	54.26	12.06
Availability Factor	76.71	82.41	0.00	94.37	94.37	18.21
Service Factor	22.83	20.79	0.00	64.19	64.19	15.92
Seasonal Derating Factor	0.12	0.00	0.00	0.90	0.90	0.24
Unit Derating Factor	1.59	0.94	0.00	7.03	7.03	1.69
Equiv. Unavailability Factor	24.88	20.11	0.00	57.33	57.33	12.28
Equiv. Availability Factor	75.00	79.19	0.00	91.81	91.81	18.09
Gross Capacity Factor	9.33	6.60	0.00	41.04	41.04	9.06
Net Capacity Factor	9.00	6.45	0.00	40.17	40.17	8.90
Gross Output Factor	40.76	35.23	0.00	63.94	63.94	13.77
Net Output Factor	39.45	34.92	0.00	62.58	62.58	13.93
Equiv. Maint. Outage Factor	4.40	2.49	0.00	42.32	42.32	7.64
Equiv. Planned Outage Factor	13.63	11.26	0.00	28.37	28.37	8.75
Equiv. Forced Outage Factor	7.60	5.06	0.00	21.20	21.20	5.64
Equiv. Scheduled Outage Factor	18.02	14.06	0.00	48.73	48.73	10.56
Equiv. Unplanned Outage Factor	11.25	7.13	0.00	50.92	50.92	9.90
Forced Outage Rate	19.28	11.27	0.00	75.31	75.31	20.08
Forced Outage Rate (demand)	10.59	6.80	0.00	27.65	27.65	7.95
Equiv. Forced Outage Rate	26.18	18.95	0.00	87.04	87.04	20.66
Eq.Forced Outage Rate demand (EFORd	13.09	9.04	0.00	33.65	33.65	8.46
Eq Unplanned Outage Rate (EUOR)	35.93	28.25	0.00	89.58	89.58	22.23
Average Run Time	43.90	23.51	0.00	562.29	562.29	126.75
Starting Reliability	98.52	98.16	0.00	100.00	100.00	18.18

Units Included in Study # 17
Sargent&Lundy
GADS Report (Based on IEEE Standard 762)

Utility	Unit Code	Region	Unit Name	Commercial Date
113 National Grid (Keyspan Energy)				
	141	NPCC	NORTHPORT #1	6/21/1967
	142	NPCC	NORTHPORT #2	5/14/1968
	143	NPCC	NORTHPORT #3	6/20/1972
	144	NPCC	NORTHPORT #4	12/29/1977
213 EXELON GENERATION CO., LLC (MAAC)				
	134	RFC	EDDYSTONE #3	9/24/1974
	135	RFC	EDDYSTONE #4	6/29/1976
292 HA Wagner LLC				
	134	RFC	HERBERT WAGNER #4	8/29/1972
308 FLORIDA POWER & LIGHT CO.				
	120	FRCC	TURKEY POINT #1	4/22/1967
312 GEORGIA POWER CO.				
	161	SERC	YATES 6	7/23/1974
	162	SERC	YATES 7	4/08/1974
708 CENTRAL LOUISIANA ELECTRIC CO.				
	103	SPP	TECHE #3	5/31/1971
719 Westar Energy (KGE)				
	110	SPP	GORDON EVANS #2	6/30/1967
722 Entergy LOUISIANA LLC				
	112	SERC	LITTLE GYPSY #2	12/31/1965
729 OKLAHOMA GAS AND ELECTRIC CO.				
	118	SPP	HORSESHOE LAKE #8	4/06/1969
732 Southwestern Electric Power Co AEP				
	109	SPP	KNOX LEE #5	3/25/1974
	111	SPP	WILKES #2	5/05/1970
	112	SPP	WILKES #3	12/24/1971
801 AUSTIN ENERGY				
	132	ERCOT	DECKER #2	8/24/1977
812 TOPAZ POWER GROUP LLC				
	151	ERCOT	DAVIS #1	4/15/1974
819 EXELON GENERATION, LLC				
	151	ERCOT	LAKE HUBBARD #1	6/18/1970
840 NRG Texas, LLC				

Utility	Unit Code	Region	Unit Name	Commercial Date
	155	ERCOT	GREENS BAYOU #5	6/16/1973
854 LOWER COLORADO RIVER AUTHORITY				
	103	ERCOT	SIM GIDEON #3	3/11/1972
868 CPS Energy				
	114	ERCOT	V. H. BRAUNIG #3	5/04/1970
	115	ERCOT	O.W. SOMMERS #1	4/27/1972
	116	ERCOT	O.W. SOMMERS #2	1/14/1974
879 EXELON GENERATION, LLC				
	142	ERCOT	GRAHAM #2	6/05/1969
880 Luminant Power				
	183	ERCOT	VALLEY #3	5/31/1971
932 XCEL ENERGY				
	116	WECC	CHEROKEE #4	11/07/1968
969 NRG ENERGY - WESTERN				
	104	WECC	EL SEGUNDO #4	4/01/1965

Current Report Criteria

Report No.: 17

Benchmark Report - Annual

Printed: 2/06/2020

Author: L. Bledin

Page: 1

Key Word:

Units: 29 **Utilities:** 20 **Unit Years:** 120.25

Description	Criteria
Unit Selection	All Units Incl Own
Unit Type	Fossil-Steam
Date Range	2014 to 2019
Periods	01 to 12
Commercial Date	1/01/1965 to 12/31/1980
MW Rating	325 to 425
1st Fuel Type	Gas(GG)

Appendix A: Benchmarking - Summer

Sargent&Lundy **Report # 18**

Benchmark Report - Summer

Created by: L. Bledin **Date Created:** 2/06/2020 **Printed:** 2/06/2020

Containing 29 Units in 20 Utilities 31.50 Unit Years

Matching the following criteria:

Unit Selection	All Units Incl Own
Unit Type	Fossil-Steam
Date Range	2014 to 2019
Periods	06 to 08
Commercial Date	1/01/1965 to 12/31/1980
MW Rating	325 to 425
1st Fuel Type	Gas(GG)

All values in this batch are Time-Based and are not weighted.

The following reports are included in this batch:

Annual Unit Performance	Annual Unit Statistics
Units Included in Study	Current Criteria

The following units are included in this batch:

NORTHPORT #1	NORTHPORT #2	NORTHPORT #3	NORTHPORT #4
EDDYSTONE #3	EDDYSTONE #4	TURKEY POINT #1	YATES 6
YATES 7	INDIAN RIVER #3	TECHE #3	GORDON EVANS #2
LITTLE GYPSY #2	HORSESHOE LAKE #8	KNOX LEE #5	WILKES #2
WILKES #3	DECKER #2	DAVIS #1	LAKE HUBBARD #1
GREENS BAYOU #5	SIM GIDEON #3	V. H. BRAUNIG #3	O.W. SOMMERS #1
O.W. SOMMERS #2	GRAHAM #2	VALLEY #3	CHEROKEE #4
EL SEGUNDO #4			

Annual Unit Performance Report for Years 2014 - 2019, Periods 06 - 08

Variable	Mean	Median	Minimum	Maximum	Range	Std. Dev.
Gross Maximum Capacity	384.45	392.00	315.67	428.48	112.81	31.26
Net Maximum Capacity	373.49	380.00	309.87	420.00	110.13	31.07
Gross Dependable Capacity	383.34	392.00	315.67	428.48	112.81	31.92
Net Dependable Capacity	372.41	380.00	309.87	420.00	110.13	31.68
Gross Actual Generation	133,345.00	134,162.00	0.00	413,267.00	413,267.00	104,775.73
Net Actual Generation	126,366.00	125,816.00	-304.00	378,361.00	378,665.00	98,351.09
Period Hours	2,156.32	2,208.00	0.00	2,208.00	2,208.00	410.73
Unit Service Hours	910.76	895.59	0.00	2,208.00	2,208.00	529.28
Pumping Hours	0.00	0.00	0.00	0.00	0.00	0.00
Condensing Hours	0.00	0.00	0.00	0.00	0.00	0.00
Reserve Shutdown Hours	1,027.09	1,054.36	0.00	1,955.22	1,955.22	507.78
# of RSH Occurences	20.59	10.20	0.00	51.40	51.40	18.36
Total Available Hours	1,937.85	2,057.96	0.00	2,208.00	2,208.00	419.02
Forced Outage Hours	126.85	74.02	0.00	569.17	569.17	130.11
# of FOH Occurences	2.23	2.00	0.00	6.20	6.20	1.45
Planned Outage Hours & Ext.	44.05	0.00	0.00	332.65	332.65	86.65
# of POH Occurences	0.12	0.00	0.00	1.20	1.20	0.25
Maintenance Outage Hours & Ext	47.57	31.65	0.00	183.05	183.05	45.74
# of MOH Occurences	0.83	0.80	0.00	2.67	2.67	0.69
Total Unavailable Hours	218.47	138.09	0.00	687.24	687.24	184.09
# of FD Occurrences	6.44	2.60	0.00	34.40	34.40	9.04
Equiv. Scheduled Derated Hrs	6.13	0.90	0.00	49.56	49.56	11.66
Actual Units Starts	20.36	9.40	0.00	50.60	50.60	17.77
Attempted Unit Starts	20.63	10.00	0.00	51.00	51.00	17.73
Years in Service	44.70	44.00	39.00	51.00	12.00	3.15

Annual Unit Statistics for Years 2014 - 2019, Periods 06 - 08

Sargent&Lundy

GADS Report (Based on IEEE Standard 762)

Report No.: 18
Printed: 2/06/2020
Unit Years: 31.50

Variable	Mean	Median	Minimum	Maximum	Range	Std. Dev.
Planned Outage Factor	2.04	0.00	0.00	15.07	15.07	4.06
Unplanned Outage Factor	8.09	6.25	0.00	26.39	26.39	6.29
Forced Outage Factor	5.88	3.35	0.00	25.78	25.78	5.88
Maint. Outage Factor	2.21	1.43	0.00	8.29	8.29	2.13
Scheduled Outage Factor	4.25	1.55	0.00	18.50	18.50	5.03
Unavailability Factor	10.13	6.25	0.00	31.13	31.13	8.47
Availability Factor	89.87	93.20	0.00	100.00	100.00	18.43
Service Factor	42.24	40.56	0.00	100.00	100.00	23.86
Seasonal Derating Factor	0.25	0.00	0.00	2.22	2.22	0.54
Unit Derating Factor	1.89	1.14	0.00	13.26	13.26	2.74
Equiv. Unavailability Factor	12.02	7.56	0.00	33.49	33.49	9.25
Equiv. Availability Factor	87.73	91.94	0.00	100.00	100.00	18.54
Gross Capacity Factor	16.11	14.61	0.00	55.87	55.87	12.77
Net Capacity Factor	15.71	14.10	-0.04	55.28	55.32	12.59
Gross Output Factor	38.31	38.61	0.00	62.80	62.80	15.29
Net Output Factor	37.39	37.83	-0.04	62.13	62.17	15.08
Equiv. Maint. Outage Factor	2.45	1.49	0.00	10.53	10.53	2.40
Equiv. Planned Outage Factor	2.08	0.00	0.00	15.07	15.07	4.13
Equiv. Forced Outage Factor	8.24	4.81	0.00	31.95	31.95	7.56
Equiv. Scheduled Outage Factor	4.53	1.85	0.00	18.53	18.53	5.21
Equiv. Unplanned Outage Factor	9.94	7.56	0.00	30.27	30.27	7.21
Forced Outage Rate	12.22	8.15	0.00	50.49	50.49	12.95
Forced Outage Rate (demand)	8.04	5.38	0.00	27.60	27.60	7.15
Equiv. Forced Outage Rate	16.86	13.93	0.00	67.08	67.08	15.71
Eq.Forced Outage Rate demand (EFORd	10.45	6.58	0.00	33.70	33.70	8.61
Eq Unplanned Outage Rate (EUOR)	20.88	18.86	0.00	72.49	72.49	17.42
Average Run Time	44.74	26.78	0.00	2,208.00	2,208.00	405.03
Starting Reliability	98.69	99.22	0.00	100.00	100.00	25.00

Utility	Unit Code	Region	Unit Name	Commercial Date
113 National Grid (Keyspan Energy)				
	141	NPCC	NORTHPORT #1	6/21/1967
	142	NPCC	NORTHPORT #2	5/14/1968
	143	NPCC	NORTHPORT #3	6/20/1972
	144	NPCC	NORTHPORT #4	12/29/1977
213 EXELON GENERATION CO., LLC (MAAC)				
	134	RFC	EDDYSTONE #3	9/24/1974
	135	RFC	EDDYSTONE #4	6/29/1976
308 FLORIDA POWER & LIGHT CO.				
	120	FRCC	TURKEY POINT #1	4/22/1967
312 GEORGIA POWER CO.				
	161	SERC	YATES 6	7/23/1974
	162	SERC	YATES 7	4/08/1974
317 ORLANDO UTILITIES/GenOn Energy				
	113	FRCC	INDIAN RIVER #3	10/04/1973
708 CENTRAL LOUISIANA ELECTRIC CO.				
	103	SPP	TECHE #3	5/31/1971
719 Westar Energy (KGE)				
	110	SPP	GORDON EVANS #2	6/30/1967
722 Entergy LOUISIANA LLC				
	112	SERC	LITTLE GYPSY #2	12/31/1965
729 OKLAHOMA GAS AND ELECTRIC CO.				
	118	SPP	HORSESHOE LAKE #8	4/06/1969
732 Southwestern Electric Power Co AEP				
	109	SPP	KNOX LEE #5	3/25/1974
	111	SPP	WILKES #2	5/05/1970
	112	SPP	WILKES #3	12/24/1971
801 AUSTIN ENERGY				
	132	ERCOT	DECKER #2	8/24/1977
812 TOPAZ POWER GROUP LLC				
	151	ERCOT	DAVIS #1	4/15/1974
819 EXELON GENERATION, LLC				
	151	ERCOT	LAKE HUBBARD #1	6/18/1970
840 NRG Texas, LLC				

Utility	Unit Code	Region	Unit Name	Commercial Date
	155	ERCOT	GREENS BAYOU #5	6/16/1973
854 LOWER COLORADO RIVER AUTHORITY				
	103	ERCOT	SIM GIDEON #3	3/11/1972
868 CPS Energy				
	114	ERCOT	V. H. BRAUNIG #3	5/04/1970
	115	ERCOT	O.W. SOMMERS #1	4/27/1972
	116	ERCOT	O.W. SOMMERS #2	1/14/1974
879 EXELON GENERATION, LLC				
	142	ERCOT	GRAHAM #2	6/05/1969
880 Luminant Power				
	183	ERCOT	VALLEY #3	5/31/1971
932 XCEL ENERGY				
	116	WECC	CHEROKEE #4	11/07/1968
969 NRG ENERGY - WESTERN				
	104	WECC	EL SEGUNDO #4	4/01/1965

Current Report Criteria

Report No.: **18**

Benchmark Report - Summer

Printed: 2/06/2020

Author: L. Bledin

Page: 1

Key Word:

Units: 29 **Utilities:** 20 **Unit Years:** 31.50

Description	Criteria
Unit Selection	All Units Incl Own
Unit Type	Fossil-Steam
Date Range	2014 to 2019
Periods	06 to 08
Commercial Date	1/01/1965 to 12/31/1980
MW Rating	325 to 425
1st Fuel Type	Gas(GG)

Appendix B: RCMT Condition Assessment Report (Redacted)

Redacted Version

PSEG

Long Island

CONDITION ASSESSMENT

OF

NATIONAL GRID

ELECTRIC GENERATION ASSETS

[redacted]

TECHNICAL REPORT

December 30, 2014, Revision 1

RCM Technologies
The Source of Smart Solutions

2500 McClellan Avenue
Pennsauken, NJ 08109

TABLE OF CONTENTS

APPENDICES

1.0 EXECUTIVE SUMMARY

1.1. Introduction

RCMT Technologies ("RCMT") was tasked by PSEG Long Island, LLC ("PSEG LI") to perform a high-level condition assessment of the National Grid Electric Generation assets that are in contract to the Long Island Power Authority (LIPA) through a Power Supply Agreement ("PSA") and Purchase Power Agreement (PPA). National Grid has three steam electric generation facilities (E.F. Barrett Power Station, Northport Power Station and Port Jefferson Power Station) consisting of eight (8) steam units with a capacity of 2200 MW. In addition, National Grid has forty two (42) combustion turbines and diesel units at eleven (11) sites with a capacity of 1650 MW.

RCMT was tasked with performing a high level condition assessment of the National Grid electric generation assets related to the PSA to ascertain whether they are in an operating condition to successfully operate for the next five (5) years (2015-2019), providing the performance required under the PSA. In addition, RCMT was to review National Grid maintenance management and capital improvement controls that would support the assets performance during the next five (5) years.

The condition assessment was conducted through interviews and presentations provided by National Grid personnel, physical inspection of all assets, and review of National Grid historical documentation and files.

1.2. Summary of Findings

RCMT has determined that the National Grid Electric Generation assets can successfully provide the performance required by the LIPA PSA & PPA over the next five (5) year period (2015-2019) under the current operational profile. (Note that RCMT also determined, as described in its December 30, 2014 supplemental report, Projections of Capital and O&M Expenditures, that assuming O&M and capital expenditures detailed therein occur as projected that the PSA units can successfully operate at least until contract expiration in 2028).

A review of historical records has revealed that the National Grid Electrical Generation assets have been reliable during the past five years resulting in summer availabilities in excess of 96% and unforced capacity (i.e., UCAP) levels that have supported LIPA requirements.

Planned capital improvement projects and major/minor overhaul scheduling will continue to support the life of these assets. The total 2015 to 2019 capital budget for the National Grid generation assets is [redacted]

Historical maintenance records did not reveal major equipment flaws in any of the eight steam generation units' steam turbines, generators, boilers and associated headers/tubing, high energy piping and associated branches/attachments, and other large rotating equipment. Port Jefferson Unit 3 is due for boresonic inspection of all rotors during the major overhaul this Fall of 2014.

Regarding Section 316b of Federal Clean Water Act, the E.F Barrett and Northport Power Stations have not received New York State Department of Environmental Conservation (NYSDEC) State Pollutant Discharge Elimination System (SPDES) permits for their circulating water systems. Until the NYSDEC provides a ruling, it is uncertain what level of modification will be required. If cooling towers are required, it is anticipated that the capital expense for E.F. Barrett and Northport would be [redacted] and [redacted] respectively. A final decision on this matter, however, is expected to be beyond the 5 year period of assessment in this report.

Physically, all of the combustion turbine units are well maintained with no known load or operational limitations preventing continued operation well into the future, despite their current age.

Original Equipment Manufacturer (OEM) and after-market product parts and service support, which are special to the combustion turbine industry, remain in place and should remain so well into the future. Spare parts availability remains in place. Additionally, the combustion turbine user community remains a viable source of technical assistance.

Existing maintenance programs and practices, specific to the National Grid combustion turbine units have a long and proven track record of providing reliable availability and service. There are no plans to alter the current programs.

Control systems have been replaced with new Digital Control Systems on most internal combustion (IC) units. This upgrade will have a dramatic impact on unit start up and operational reliability. The original electronic and relay based systems were the single most frequent cause of poor starting reliability and failures in service. Those problems will be significantly reduced if not completely eliminated. Additionally, with improvements in these areas the service life of the units will benefit significantly.

Individual Scorecards have been provided for each of the eight (8) steam units and each of the GT sites that were visited. These scorecards found in Appendix 1.1.

2.0 ASSESSMENT OF ELECTRIC GENERATION ASSETS

2.1. National Grid Management Programs & Controls

Productive power generation station service life and reliability can only be achieved through the presence and execution of effective management procedures and oversight; essentially, governance programs. Therefore, to properly complete the task to assess National Grid's PSA related power plants, the existence of such governance programs was reviewed. In summary, National Grid has a comprehensive array of effective programs. These programs, if maintained and followed, and in conjunction with adequate Capital and O&M expenditures, should provide excellent service and reliable performance. Historically, National Grid's performance has been excellent with a Summer Availability Factor of over 95%. This is the critical period of time for capacity demand on the LIPA grid. In addition, the PSA contract requires a specific UCAP commitment to the NYSISO with penalties to National Grid for not meeting the UCAP guarantees. National Grid Demonstrated Maximum Net Capability (DMNC) testing performance has been excellent and, combined with reasonably low DMNC Weighted EFORd, has resulted in National Grid exceeding the UCAP [DMNC x (1-EFORd)] Net Capability (NC) guarantees. Finally, CT Unit Startup Reliability has been maintained at 95% over the past six years. These figures are shown in Appendix 1.4 - PSA Units Summer Availability Factor / Annual DMNC Weighted EFORd / PSA CT Unit Startup Reliability.

The aforementioned overall level of performance supports the notion that Capital and O&M projected expenditures are appropriate for running repairs, major & periodic overhauls, and planned summer preparation outages. National Grid management has committed to maintaining both Capital and O&M expenditures sufficient to support the existing system performance for the next five years and through the full term of the PSA contract in 2028. We do not see evidence to the contrary.

The National Grid five 5-Year Capital Plan is organized to address reliability, legal & regulatory, safety, and miscellaneous other areas. However, reliability and legal & regulatory issues are projected to consume the majority of expenditures. Annual capital expenditures vary from [redacted] to [redacted] year. Appendix 1.5 - National Grid Capital Plan 5 Year Budget for 2015 -2019 outlines by individual line item the expenditures for all PSA units. It is our understanding that LIPA annually reviews the National Grid 5-Year Capital Budget and must approve the capital expenditures for the following fiscal year. The 2015-2019 Capital Plan is presently being reviewed by LIPA. National Grid receives some contractual return on these capital investments; therefore, LIPA must approve the expenditures before they are made. For this reason, the team believes that a constant level of annual capital improvements will be made by National Grid through the term of the PSA contract. At present, the only known large capital investment risk is the potential regulatory requirement by NYSDEC to install cooling towers at E.F. Barrett and Northport Power Station at some time after the present 5-year budget. This potential requirement is discussed later in the report.

Even more important to maintaining a high level of performance is the level of O&M expenditures for running repairs and scheduled overhauls & outages. During the condition assessment, data breakdown of O&M costs was not provided to the review team. However, based upon a figure presented to LIPA in 2009, the team estimates that the annual National Grid O&M expenditures are in the order of [redacted] The team has not been made privy of any terms and conditions of the PSA or PPA contract and, therefore, cannot make a judgment relative to required expenditures in these contracts.

As described previously in this report, the National Grid generation fleet consists of three major steam generating stations (i.e., Northport, Port Jefferson and E.F. Barrett) and eleven (11) smaller combustion turbine stations (including those located at steam stations). All of the combustion turbine stations are under the jurisdiction of one division manager, similar to each steam station. The importance of this is that all four (4) divisions organizationally report to the same senior manager; therefore, all the divisions/locations implement and follow the same uniform set of programs, with some exceptions to applicability, and share experience and insight across locations.

The review of management programs focused on those most critical to provide extended service life and high reliability performance. Budget control programs, while also essential in many respects, were not reviewed. Reviewed programs included, Personnel Safety, Operational Procedures, Work Management (CMMS), Preventative Maintenance (PM), Outage Planning & Scheduling, Capital Projects/Improvements, Boiler/Pressure Vessel Code Repair, Condition Assessment (CAP), Electrical Equipment Testing, Root Cause Analysis (RCA) and documentation and equipment history record systems. Each will be discussed in brief and assessed to their effectiveness.

The first program reviewed was the Personnel Safety Program. As this is the single most important program and from which the success of overall operations follows, it has the highest priority and impact. To that point, the focus on plant safety at the National Grid facilities appears to be the top priority. Safety is emphasized at all times in every phase of the operation. The result of these efforts is that National Grid has achieved an industry 2nd Quartile performance with an OSHA Recordable Rate of 1.55 and Lost Time Incident

Rate of 0.77, both per 200,000 man-hours. The goal of 1st Quartile is targeted for this year.

This level of success has been achieved with total top to bottom participation in several committees tasked to review everything safety related. The committees are: Safety Strategy (high level review of corporate safety measures), Safety Committee Chairman Oversight (meeting of all local plant level committee chairmen), Division Safety (local plant level committee chaired by union member with management support), Process Safety (development of Safety Key Process Indicators), Tool & Equipment (review tool concerns and approval of new items), Learning Advisory (review of training plans and needs), Policy & Procedure (reviews and revises new and existing procedures), Emergency Response Team (ensures training and qualifications), and Hold-Off (reviews and revises implementation). These nine (9) committees cover the key processes in the organization that directly impact safety and have contributed to the commendable record. However, Safety Advocates are the biggest key to the program's overall success. These consists of two (2) union members who are assigned full time to address safety concerns. They have direct access to upper management, as well as authority to act as necessary.

All four (4) divisions, being centrally managed, follow the same basic set of Operational Procedures. There are generic procedures that apply to each location, such as station security, hurricane/storm preparation, safety, Spill Control and Countermeasures, etc. In addition, each location has operational procedures specific to the units at each location, such as: Start-up/Shutdown procedures, unit/equipment operation limitations, control system calibrations, operational In-service checks, etc. In both cases, system-wide and plant specific procedures, all formal procedures reside on computer platforms and are accessible whenever needed for reference or documentation.

Plant specific operation procedures are usually implemented by signing printed out hard copies that are then forwarded for management review and record keeping. Specific equipment operational data, if not on hard copy checklists, exists in the unit Digital Control System (DCS) history, which all steam & CT units have. This procedure set is robust, well managed, effectively implemented and updated regularly when necessary.

Effective generating station maintenance management is essential for effective reliability performance. To address this need, the generating stations reviewed all utilize Maximo for their computer based Computer Maintenance Management System (CMMS) requirement. (Maximo is in use currently but will be replaced by SAP in the future). This system is used to identify, plan, schedule, document execution/completion, and maintain equipment history records for all Demand (daily) and Preventative (PM) maintenance activities. It is managed by a work coordinator/planner at each location and overseen by the Maintenance Manager at a higher level. This system is used to track repairs, reduce maintenance costs, and provide equipment service life, performance and equipment history.

Each division/location has a comprehensive Preventative Maintenance (PM) program, modified and enhanced over the years. This PM program provides scheduled intervals for routine maintenance activities such as lubrication, electrical testing and overhaul of auxiliary pumps and motors. Each station follows the same basic frequency intervals. The PM program schedule and equipment history reside in the CMMS Maximo system. It is managed by the work planner and appropriate area manager (maintenance or controls). It is an effective program.

Outage Planning & Scheduling (P&S) includes all the activities required and associated with complete periodic and major overhauls, or capital improvements to steam turbine-generators and boilers, as well as industrial frame combustion turbine-generators. This is a critical and essential program to manage major maintenance and improvement projects cost effectively, compliant with outage schedules and manpower resources, to deliver a very high level of quality and accuracy at any point in time before or during a project. It is essential for cost control and unit availability. To this critical program, the reviewed stations have an in-house developed program in place. Maximo is used to provide cost control information enhancing the Primavera P6 (P6) based project management system. All major P&S requirements involve an extremely detailed level of activity planning and sequencing, and estimates of duration and tracking of progress at any point in time. National Grid has the required personnel in the form of planners and analysts to update this system on a daily basis to continually update project status, including the effects of contingencies. P6 is extremely accurate and useful in managing overhauls and projects within budget and on schedule. In addition, all major equipment history updates are part of this program and feed into future project planning. This tool is used effectively to a very high degree. The results of major overhauls and projects completed with this program are reflected in the performance and reliability of the reviewed generators.

The Capital Projects/Improvement program is where all major equipment and/or facility improvements of significant monetary value are identified, budgeted and scheduled. Projects such as control system upgrades, major rotating equipment replacements, boiler tubing replacements, etc., are budgeted for and scheduled. This five (5) year forward looking document, in addition to serving as the obvious budget vehicle, provides input into the long range Outage Planning & Scheduling program. This is a living document, updated annually. Integration into the Planning & Scheduling program, in most cases during scheduled unit outages, assures the timely and cost effective completion of each approved project.

As part of the overall equipment maintenance program, where most major physical maintenance is completed using in-house skilled resources with very limited use of contractors, National Grid possesses a complete Pressure Vessel Repair Program and "R" stamp, a particular certification to work on pressure vessels, required by New York. This extensive program is extremely detailed as to its jurisdiction, requirements, methods of repair, quality control, and documentation. It required a major effort to develop this program, have it approved, and then maintain it. To this degree, the entire code manual was reviewed and several sample project document records were reviewed with satisfactory results. The ability to perform code "R" stamp repairs is an asset to National Grid and speaks well of the overall maintenance program.

Given the age of the reviewed units, particularly the steam units, pressure vessel and high energy piping systems are a major concern, as it is in the industry in general. To address this concern, National Grid has a well-developed Condition Assessment Program (CAP) to inspect, assess, monitor, and recommend corrective actions. The program is managed by the Power Engineering Department (in coordination with the power stations), and staffed with experienced personnel in this engineering specialty. Routine schedule and frequency of testing of all subject high energy piping systems is integrated into the Outage Planning & Scheduling system and is completed during unit outages. To this degree, National Grid has a firm program in place and is pro-active in monitoring and addressing concerns this subject area encompasses.

Testing and maintenance of major electrical equipment, such as motors and generators, has always been a high priority at these stations. Generator requirements are part of major overhaul P&S. Large pumps and fans, as well as smaller auxiliary motors, are maintained within the Maximo (CMMS) system where individual equipment histories reside. Maintenance is up to date. With the recent separation of National Grid generation from the electric transmission & distribution company, electrical breaker and transformer maintenance and testing, previously performed by Substation Maintenance Department, now has to be done by the plants themselves. To address this need an in-house major electrical testing and maintenance group has been formed. It is managed by managers with a high level of experience in the subject matter (i.e., previous substation experience). At the current time maintenance of this equipment is satisfactory and is expected to be maintained, perhaps at a higher level due to ownership, going forward. In addition, all NERC related relay testing will also be addressed with the new group.

Another noteworthy program used by National Grid to address major equipment issues is Root Cause Analysis (RCA). As required, following a major equipment failure or repeated component failure (e.g., Salt Water Circulator Pump Shaft material failure), the collective group of plant engineers, Power Engineering Department engineers, and maintenance managers form a committee to investigate the failure. They follow a formal process to investigate the problem, determine necessary forensics, make engineering or maintenance practice changes, implement recommendations and report document their findings. This program has been effective to reduce and/or eliminate and pre-empt repeated failures.

The programs discussed above are the major programs reviewed as part of this task. Although there may be others of similar importance, the programs reviewed and reported form the foundation for effective power station operations. These programs for the most part represent mature programs, developed and revised with years of experience. These programs appear to work and be effective in providing good performance in terms of reliability and service life. However, they are tools and tools need to be used to be effective. To that point, the review not only covered their existence, but how and if they are used. It is the opinion of this review that these programs are used almost daily and provide the basis for good management decisions. Their usefulness depends on those willing to use and trust the information provided for guidance. The reported programs meet that need and will assist in the continued operation of the units reviewed.

2.2. Steam Generation Facilities

2.2.1 Northport Power Station

Northport Power Station is the largest of the National Grid electric generation assets. It represents 39% of the total assets and 68% of the steam generation assets. The Station is comprised of four (4) 375 MW units that can be natural gas and/or low sulfur residual fuel oil fired. The units went into commercial operation in 1967, 1968, 1972 and 1977. They are each equipped with General Electric tandem compound reheat four flow LP stage steam turbines and generators with shaft driven boiler feed pumps and Combustion Engineering tangentially fired, forced circulation boilers. Turbine throttle conditions are 2520 psig, 1005°F SH, 1005°F RH. Although the general design and configuration of each unit is identical, Units 2 & 4 are mirror images of Units 1 & 3.

The initial boiler design for Units 1 & 2 was pressurized furnaces with consideration for coal firing. Flue gases were discharged from the air preheaters to mechanical dust collectors before discharge to the stack. Initial high sulfur fuel oil firing resulted in the pressurized furnace flue gas caused leakage and safety concerns, stack opacity problems, and excessive steam temperatures resulting from an over designed superheater tube surface. Both units were modified in the 1970's by adding electrostatic precipitators, induced draft fans, and second stage superheater feedwater sprays.

None of the units four boilers have identical tubing configuration as a result of the struggle to control superheater temperatures without excessive feedwater sprays. Appendix 1.2 – Northport Units 1-4, Major Boiler Modification History, Description and Listing, rev.19 provides an overview of the boiler problems and modifications over the past 47 years.

[redacted]

While touring the station all personnel were observed wearing the appropriate safety attire, and areas where work was being progressed was marked off to avoid access. Northport has an excellent safety record with no lost time accidents in 3½ years.

Northport Power Station is subject to the National Grid's high energy piping Condition Assessment Program (CAP). This program tests and inspects main, hot & cold reheat steam piping and boiler feed, boiler header and boiler piping. CAP includes inspections of shop and field welds, branch connections, thermowells, gamma plugs, pipe supports and support hangers and cans. In addition, boiler feed discharge piping is inspected ultrasonically to evaluate flow accelerated corrosion thickness damage. A review of Northport summary records of these evaluations did not reveal any major concerns and all findings were corrected when required.

Documentation reviewed did not determine any concerns associated with turbine or generator rotors or generator fields. The turbine/generators are overhauled on a 7 year cycle.

Northport Power Station has a [redacted] capital budget proposed to LIPA for the five year period 2015 through 2019. Several station improvements that anticipated to be made are mentioned in the unit scorecards found in Appendix 1.1; however, there are numerous other anticipated improvements to the common plant that are worth identifying:

- Units 1-4 Auxiliary and Starting Transformer upgrades from 2014-17 for [redacted]
- Offshore Platform Storm Protection and Equipment Hardening from 2014-18 for [redacted]
- Miscellaneous building and structural repairs from 2014-15 for [redacted]
- Waste Water Treatment equipment replacements in 2014-15 for [redacted]
- Fuel Oil Tank 1 upgrades from 2014-15 for [redacted]

Regarding the Section 316b of Federal Clean Water Act discussed in the Summary of Findings, Northport Power Station has not received a NYSDEC SPDES permit for its circulating water system. National Grid has proposed installing variable speed drives (VSD) on circulating water pumps, condenser vacuum priming system and fish friendly travelling screens which have been budgeted for 2017-18. NYDEC has proposed cooling towers. Until the NYSDEC provides a ruling, it is uncertain what level of modification will be required. If cooling towers are required, it is anticipated that the capital expense for Northport would be [redacted] A final decision on this matter is expected beyond the 5-year period of assessment in this report.

2.2.2 E.F. Barrett Power Station

E.F. Barrett Power Station is comprised of two 175 MW units that went into commercial operation in 1956 and 1963. Both units are equipped with General Electric tandem compound reheat triple flow LP stage steam turbines and generators and Combustion Engineering tangentially fired, natural circulation boilers operating at a throttle pressure of 1825 psig, 1005°F SH, 1005°F RH. These units are sister units to those at the Port Jefferson Power Station. Unit 1 originally burned coal and both units are now equipped to fire natural gas or low sulfur residual fuel oil. With the plant adjacent to the Transco natural gas pipeline, the primary fuel is natural gas. The fuel oil barge unloading dock is presently not serviceable and awaiting structural repairs in 2014-15. Until these repairs are completed, the units are constrained from firing fuel oil. Although the general design and configuration of each unit is identical, Units 1 & 2 are mirror images of each other.

[redacted]

While touring the station, all personnel were observed wearing the appropriate safety attire, and areas where work was being progressed was marked off to avoid access. Barrett has a less than satisfactory safety record with a lost time accident in April 2014.

E.F. Barrett Power Station is also subject to National Grid's high energy piping Condition Assessment Program (CAP). This program tests and inspects main, hot & cold reheat steam piping and boiler feed, boiler header and boiler piping. CAP includes inspections of shop and field welds, branch connections, thermowells, gamma plugs pipe supports and support hangers and cans. In addition, boiler feed discharge piping is inspected ultrasonically to evaluate flow accelerated corrosion thickness damage. A review of Barrett summary records of these evaluations did not reveal any major concerns and all evaluation findings were corrected when required.

Documentation reviewed did not determine any concerns associated with turbine or generator rotors or generator fields. The turbine/generators are overhauled on a 7 year cycle.

E.F. Barrett Power Station has a [redacted] capital budget proposed to LIPA for the five-year period 2015 through 2019. Several anticipated improvements have been mentioned in the unit scorecards found in Appendix 1.1; however, there are several other expected improvements to the common plant that are worth identifying:

- CEMS hardware & software upgrades in 2014 for [redacted]
- Reverse Osmosis System upgrades in 2014 for [redacted]
- Emergency Power and System upgrades in 2014 for [redacted]
- DCS upgrade for both units in 2016 for [redacted]
- Purchase spare Starting Transformer in 2014 for [redacted]

National Grid has proposed a 650MW combined cycle project for the replacement of the Barrett steam units. This proposal is on hold at this time.

Regarding the Section 316b of Federal Clean Water Act discussed in the Summary of Findings, E.F. Barrett Power Station has not received a NYSDEC SPDES permit for their circulating water system. Similar to Northport, National Grid has proposed installing variable speed drives (VSD) on circulating water pumps, condenser vacuum priming system and fish friendly travelling screens, which have been budgeted for 2015-18. NYDEC has proposed cooling towers. [redacted] If cooling towers are required, it is anticipated that the capital expense for E.F.Barrett would be [redacted] A final decision on this matter is expected beyond the 5-year period of assessment in this report.

2.2.3 Port Jefferson Power Station

Port Jefferson Power Station is comprised of two 175 MW units that went into commercial operation in 1958 and 1960. Both units are equipped with General Electric tandem compound reheat triple flow LP stage steam turbines and generators and Combustion Engineering tangentially fired, natural circulation boilers operating at a throttle pressure of 1825 psig, 1005°F SH, 1005°F RH. These units are sister units to those at the E.F. Barrett Power Station. Both units originally burned coal and are now equipped to fire natural gas or low sulfur residual fuel oil. Burning of natural gas, though, is sometimes constrained by low system gas pressure. Although the general design and configuration of each unit is identical, Units 3 & 4 are mirror images of each other.

The first two 50 Mw units at Port Jefferson (Units 1 & 2) were placed in commercial operation in 1948 & 1950 and formally retired in 1994.

During the past nine years, the Port Jefferson Capacity Factor has significantly and continually decreased from 56.1% in 2005 to 10.4% in 2013. Logic might suggest that the longer a unit sits idle, the greater the risk of startup failure when requested to operate. However, the Summer EFORd improved as shown below:

	Summer EFORd		
	PJ3	PJ4	Site
2011	0.61	1.17	0.88
2012	0.03	0.13	0.08
2013	0.01	0.05	0.03

[redacted]

While touring the station, all personnel were observed wearing the appropriate safety attire and areas, and where work was being progressed it was marked off to avoid access. Port Jefferson has an exceptional safety record with no lost time accidents in 6½ years.

Port Jefferson Power Station is also subject to National Grid's high energy piping Condition Assessment Program (CAP). This program tests and inspects main, hot & cold reheat steam piping and boiler feed, boiler header and boiler piping. CAP includes inspections of shop and field welds, branch connections, thermowells, gamma plugs pipe supports and support hangers and cans. In addition, boiler feed discharge piping is inspected ultrasonically to evaluate flow accelerated corrosion thickness damage. A review of Port Jefferson summary records of these evaluations did not reveal any major concerns and all evaluaiton findings were corrected when required.

Unit 3 is due for boresonic inspection of all turbine/generator rotors during the major overhaul this Fall 2014. A prior inspection of Unit 3 rotors in 2007 recommended re-inspection in 6 years. Unit 4 turbine and generator rotors were inspected boresonically in 2010 and recommended for re-inspection in 10 years. The turbine/generators are overhauled on a 7-year cycle.

Port Jefferson Power Station has a[redacted] capital budget proposed to LIPA for the five-year period 2014 through 2018. Several expected improvements have been mentioned in the unit scorecards found in Appendix 1.1; however, there are several other improvements to the common plant that are worth identifying:

- Spare 177 MW Unit Generator Field Rewind in 2014 for [redacted]
- Spare Boiler Feed Pump Motor in 2014 for [redacted]
- Spare Condensate Pump Motor in 2015 for [redacted]
- Spare Gas Recirculation Fan Motor in 2015 for [redacted]

Regarding the Section 316b of Federal Clean Water Act discussed in the Summary of Findings, Port Jefferson Power Station has received a NYSDEC SPDES permit for their circulating water system. This permit requires installing variable speed drives (VSD) on circulating water pumps, condenser vacuum priming system and fish friendly travelling screens, which will be completed in 2014.

3.0 Combustion Turbine Generation Facilities

3.1. General Overview

The National Grid Combustion Turbine (CT) facilities consist of forty-two (42) generating units, in peaking operation, representing 1650 MW total, or 43% of the total National Grid installed capability. These units were installed between the years 1962 and 2002. This fleet of units is well diversified with a broad variety of unit types, from early prototype to state-of-the-art models. The fleet consists of aero-derivative jet gas turbines (FT4 and LM), heavy industrial frame gas turbines (type 5 and 7), and diesel-generators, each with their own operating characteristics. The facilities are distributed across the Long Island service area and fill a variety of requirements such as bulk NYISO generation, area protection and black start services. Some locations are single unit locations and others are multiple unit locations for a total of eleven (11) total stations. Specific unit model types and station descriptions are detailed in Appendix 1.3 – National Grid Electric Generation Scorecards (Steam & GT).

The large locations equipped with multiple units are manned locations. Management and skilled workforce personnel report daily (Monday through Friday) to these locations and work on site or out from these locations. The large manned locations include E.F. Barrett, Glenwood, Holtsville, Port Jefferson and Wading River. The remaining locations are either single unit or multiple smaller unit locations and are unmanned. Personnel report to the unmanned locations to perform inspections, operations or maintenance as needed, from the manned stations.

The forty-two (42) units fall into one of two (2) categories, the Power Supply Agreement (PSA) or the Power Purchase Agreement (PPA). The PSA units consist of all units except the four (4) LM6000 units located two ((2) each) at Glenwood and Port Jefferson. Both the PSA and PPA units are contracted exclusively to the Long Island Power Authority (LIPA).

Following peak in-service (operation) hours in the 2000 through 2005 timeframe, the operation of the PSA units has levelized around 10,000 Fired Hours total (250,000 MWH total) and the PPA units around 7000 Fired Hours total (280,000 MWH total) annually since 2005. Factors contributing to this decline from the peak include increased steam plant availability, milder temperature conditions, increased Independent Power Producer generation and system interconnects (Neptune and Cross Sound cables). However, despite the decline in operation from former peak levels, the importance of the CT unit availability and reliability remains essential. Being installed on Long Island with the ability of the units to operate on demand when needed, within a few minutes' notice, by remote control, makes the units vital in terms of providing flexibility in meeting the scheduled and emergency energy needs of the LIPA customer.

Importantly, the availability of these units provides 10 minute non-synchronized reserve from which economic power purchases can be made by LIPA. Additionally, the low operation and maintenance costs per installed kilowatt make these units economical for stand-by operation and reserve capability as well. These benefits of CT type units, in addition to meeting peak load generating requirements, play an important role in providing available installed generation capability at economical rates.

In summary, despite the decline from higher peak load operation of earlier years (2000-2005), operational requirements since then have settled at a relatively consistent annual level that does not appear to be in further decline. To that end, the National Grid CT units play an important role to Long Island generation and must be maintained properly to ensure their reliability remains in a high state of readiness. To meet this challenge, the National Grid units are managed effectively with the general management programs discussed in Table of Contents, Section No. 2.1 of this report. The units are well maintained and will meet current or increased service levels for the 2014 through 2019 timeframe of this assessment task.

3.2. System Performance

Combustion Turbine units used in peaking operation such as the National Grid fleet are generally evaluated by three (3) performance measurements. These are Unit Availability Factor, Start up Reliability and Demand Maximum Net Capability (DMNC). In addition, of more importance than Unit Availability, is Summer Unit Availability. This is due to the fact the LIPA service area is a summer peak load system and, as such, summer availability is more critical than annual availability. Thus, since it is more important and closely monitored, all planned maintenance requirements are scheduled with focus on that goal.

For the summer of 2013 operating period (June 1st through August 31st), the PSA fleet Summer Availability Factor was 90.73%, while the PPA fleet Summer Availability Factor was 75.89%. Each of these levels is lower than recent historical performance. The main drivers for the PSA units were several untimely bearing failures on E.F. Barrett Units Nos. 1 and 8, and a main breaker failure on E.F. Barrett No. 9, which also impacted No. 10's breaker cubicle. The significant driver for the PPA units was a single engine failure occurring on Port Jefferson GT No. 3 (i.e., compressor blade failure, no spare engine) for almost the entire summer operating period. Appendix No. 1.3, Item 9 details Summer Availability Factors by unit from 1999 through 2013 for the PSA units and Appendix No. 1.3, Item 10 for the PPA unit from 2002 through 2014. Both charts illustrate the 2013 performance levels to be below average and an exception to past performance, and is not considered to be a predictor of future performance.

Regarding EFORd for the gas turbine fleet; the metric is not given the same weight in performance evaluation as does Summer Availability. As discussed previously, Summer Availability is the main focus. All efforts primarily drive to that goal. EFORd is tracked and monitored, but for gas turbines in peaking operation it is not a good indicator of annual performance. This is due to the fact that the EFORd calculation formula, among other variables, considers failed starts to be forced outage events (in the numerator, even though they may be of short duration), and low Service Hours of operation (in denominator). These both tend to skew the calculation unfavorably; subsequently, it does not have much value for evaluation purposes.

Starting Reliability is a critical measure of successful starts versus called starts (by the System Operator), on an annual basis. Over the last five (5) year period, the PSA units have averaged 95% Starting Reliability while the PPA units are in the 97% range. Both of these performances are considered good given the nature of their peaking operation, especially the PSA units due to their age and long periods of stand-by service. The 2009 through 2013 Attempted Starts vs Successful Starts and Starting Reliability calculation for each specific unit is provided in Appendix No. 1.3, Item 11. Newly installed and/or planned to install, Digital Control Systems (DCS) on the PSA units will improve this performance even further, as will additional operation. No decline from these levels should be expected during the next five (5) year period.

Regarding DMNC, the PSA units have a demonstrated 1600 MW total for the most recent 2013-14 winter test and 1318 MW total for the 2013 summer test period. Discounting the retirement of four (4) units (i.e., EFB7 and Montauk 2, 3, and 4 – total 24 MW), the summer and winter totals have remained consistent with previous levels. There are no significant declining trends and these totals should remain at current levels for the next five (5) year period.

The PPA units have demonstrated 160 MW total and 192 MW totals for the 2014 summer and 2013-2014 winter test periods. These units have not shown a declining performance trend and can be expected to maintain consistent levels of capability over the next five (5) year period.

3.3. Capital Improvements

The Capital Improvement Program for the National Grid Combustion Turbine fleet follows the same structure and justification system as do the steam plants. Needs are forecasted out over a five (5) year period and updated annually. In general, total budgets are somewhat levelized, save for major exceptions. The Capital Improvement Program includes projects of a repetitive nature which are required annually and also one-time improvements. The five (5) year plan serves as a major input into the Planning & Scheduling program discussed in Section 2.1. Reviewing the plan at any point in time illustrates the foresight and direction of management concerns for these facilities.

The capital projects are listed in detail in Appendix 1.3, Item 1e & 1f. Looking at the five (5) year plan for the CT units, based on experience, the near years are typically the easiest and most accurate years to project, and those years contain the most detailed estimates. The outer years are less well estimated, or anticipated, because while repetitive project needs are defined, one-time needs are not so well defined in the outer years. For this reason the CT Capital Budget varies from a total o[redacted] However, looking at the planned projects, the repetitive projects are consistent at [redacted]level over the next five (5) years. This will necessarily need to be supplemented going forward when "as needed" projects are identified.

Repetitive projects are routine and occur each year. They include such projects as aero-derivative turbine blade and vane replacements and fuel manifold replacement used during major engine overhauls. Also included as repetitive, are "Minor Capital Addition" projects, which typically capture projects unde[redacted]as they occur during the year.

Non-repetitive projects in the five (5) year plan include projects such as Remote Terminal Unit (RTU) upgrades (at East Hampton, E.F. Barrett, Glenwood, Holtsville, South Hampton, Southold, W. Babylon and Wading River), Disturbance Monitoring Equipment installations (E.F. Barrett, Holtsville and Shoreham), exhaust plenum and elbow replacements (E.F. Barrett and Holtsville), generator rotating cooling fan replacements (E.F. Barrett), exhaust stack replacements (E.F. Barrett, Holtsville and Wading River), CO2 fire protection system replacements (Wading River), turbine casing replacements (Wading River), and inlet duct replacement (Holtsville and W. Babylon). Review of the overall Capital Improvement Projects program shows it as robust and well planned out. The program will assist greatly in the continued operation of these units for the next five (5) years.

3.4. Gas Turbine 5000 Start Rotor Issue

All of the National Grid General Electric (GE) frame model gas turbines are subject to in the industry wide rotor life issue, as advised by GE, the Original Equipment Manufacturer (OEM), via Technical Information letter 1576 (TIL 1576). TIL 1576, initially issued in 2007, placed an end of rotor life hard limit of 5,000 factored starts or 100,000 hours operation, whichever came first, on these units, at which time it was recommended the rotor be removed from further service with no option for continued service.

The initial TIL was very restrictive regarding operation beyond 5,000 factored starts. As a result of the implications to the user community, GE, after further analysis, issued a revised TIL 1576 in 2011 (Appendix No. 1.3, Item 12). The current recommendation is that following complete rotor disassembly, extensive Non Destructive Examination (NDE) analysis, and application of proprietary algorithms and material data information, results can be combined with design analysis and specific turbine operating histories to provide recommendations for rotor refurbishment, replacement and/or continued service.

Thus, the 5,000 factored start hard limit for rotor life was removed. However, only following performance of extensive inspection and analysis, pending satisfactory results, would additional service be considered with reduced inspection intervals. This TIL revision provides relief and options to the industry and certainly the National Grid units.

National Grid has been very pro-active to comply with the recommendations of TIL 1576. Prior to the latest revision lifting the hard start limit, National Grid had replaced the original turbine rotors in the Southold and South Hampton units (Southold with a purchased used rotor and South Hampton with the rotor removed from EFT Unit No. 7). Additionally, National Grid completed extensive research of all historical operating logs and data to accurately determine the true factored starts of each unit. These results are shown in Appendix No. 1.3, Item 13. Based on this accurate verified data and the average projected annual number of starts per unit, there are two (2) units which will reach the 5,000 factored start limit during the 2015-2019 time period. These are E.F. Barrett Unit Nos. 6 and 8 (Unit No. 2 is projected to be due in 2020). National Grid plans to perform all recommended inspections at the advised limits as they become due and, based on prior National Grid and industry experience to date, anticipates rotor life to be extended. The probability to not extend the life of these units is extremely low. All remaining GE units are projected to reach the starts limits beyond the current PSA contract expiration date of 2028.

The National Grid machinery insurance carrier has accepted this program.

APPENDIX 1.1

National Grid Electric Generation Scorecards (Steam & CT)

National Grid Steam Station Units

E.F. Barrett Unit 1

Executive Summary:
E.F. Barrett Unit 1 is a 175 MWG unit placed in initial operation in 10/25/56. The unit is equipped with a GE turbine/generator and Combustion Engineering Tangential fired steam boiler which will fire natural gas or #6 low sulphur residual oil. Summer availability from 2003 to 2012 has been greater than 98%. In 2013, the summer availability was reduced due to the extension of a turbine major overhaul extending into the summer months. The unit EFORd for the past 10 years has been below 4% except in 2012, the EFORd was 21.8% as a result of substation flooding of Main Bank #1 after Super Storm Sandy. The Station average Capacity Factor for the past five years was approximately 33%.
A 650 MW combined cycle unit has been proposed the replacement of both Barrett steam units.

Managed Systems

Operations	[illegible]	Work Mgt	Spare Parts

Comments: Operations and maintenance procedures are in place. The maintenance work management system (CMMS) is used to identify, plan, schedule, document execution & maintain history for all DM & PM.

Financial Planning

Base	Outage	Capital	

Comments: The 2014 thru 2018 Capital Budget for the Barrett Station is in excess [redacted]

Material Condition/Major Systems

[illegible]	Forced Air	Environmental	
Service Water	Circ Water	Inst Air	
Service Air	Condensate	Feedwater	
Vacuum	Seal Stream	Water Treatment	
Extraction Steam	Elec Distribution	DCS	

Comments: At present, the mooring cells at the fuel oil barge delivery dock are not capable of receiving fuel oil deliveries. A Capital Work Order for the mooring cells and dock repairs [redacted] has been approved for the Fall of 2014. Section 316b of the Federal Clean Wate Act could requires cooling tower steam condensing for both units which would require a significant capital expenditure (estimated a[redacted] Permit has not been issued by NYSDEC and it is expected that a capital investment decision for cooling towers will be beyond the 5 year assessment period. National Grid has proposed VSD for Circ. Water Pumps and Fish Friendly Traveling Screens.

Material Condition/Major Components

Turbines	Generators	Boilers	
Breakers	Transformers	Piping	
Stack			

Comments: Factory Mutual Boiler Inspection in 2014 did not identify any major problems with the boiler and accessories; however, the age of the boiler piping and headers requires continual monitoring and replacements. Headers, pendants and tube banks have been replaced during the past ten years and National Grid will be replacing the units LTSH Upper Bank and economizer bank in 2014 and 2016, respectively.

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

(red)	Not without Major Intervention
(yellow)	Threatened without Minor Intervention
(white)	Yes
(green)	More than Adequate

National Grid Steam Station Units

E.F. Barrett Unit 2

Executive Summary:

E.F. Barrett Unit 2 is a 175 MWG unit placed in initial operation in 10/24/63. The unit is equipped with a GE turbine/generator and Combustion Engineering tangential fired steam boiler which will fire natural gas or #6 low sulphur residual oil. Summer availability from 2003 to 2013 has been greater than 98%. In 2013, the summer availability was reduced due to the extension of a summer preparation outage extending into the summer months. The unit EFORd for the past 10 years has been below 5%. In 2012, the Station EFORd was 13% as a result of substation flooding after Super Storm Sandy. The Station average Capacity Factor for the past five years was approximately 33%.

A 650 MW combined cycle unit has been proposed the replacement of both Barrett steam units.

Managed Systems				Comments: Operations and maintenance procedures are in place. The maintenance work management system (CMMS) is used to identify, plan, schedule, document execution & maintain history for all DM & PM.
Operations	Maintenance	Work Mgt	Spare Parts	
Financial Planning				Comments: The 2014 thru 2018 Capital Budget for the Barrett Station is in excess of [redacted]
Base	Outage	Capital		
Material Condition/Major Systems				Comments: At present, the mooring cells at the fuel oil barge delivery dock are not capable of receiving fuel oil deliveries. A Capital Work Order for the mooring cells and dock repairs for [redacted] has been approved for the Fall of 2014. Section 316b of the Federal Clean Wate Act could require cooling tower steam condensing for both units which would require a significant capital expenditure [redacted] Permit has not been issued by NYSDEC and it is expected that a potential capital investment decision for cooling towers will be beyond the 5 year assessment period. National Grid has proposed VSD for Circ. Water Pumps and Fish Friendly Traveling Screens.
Fuel Delivery	Forced Air	Environmental		
Service Water	Circ Water	Inst Air		
Service Air	Condensate	Feedwater		
Vacuum	Seal Stream	Water Treatment		
Extraction Steam	Elec Distribution	DCS		
Material Condition/Major Components				Comments: Factory Mutual Boiler Inspection in 2014 did not identify any major problems with the boiler and accessories; however, the age of the boiler piping and headers requires continual monitoring and replacements. Headers, pendants and tube banks have been replaced during the past ten years and National Grid will be replacing the units ashpit tubing in 2015.
Turbines	Generators	Boilers		
Breakers	Transformers	Piping		
Stack				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention	Threatened without Minor Intervention	Yes	More than Adequate

National Grid Steam Station Units

Northport Unit 1

Executive Summary:
Northport Unit 1 is a 375 MWG unit placed in initial operation in July 1967. The unit is equipped with a GE turbine/generator and Combustion Engineering tangential fired steam boiler which will fire natural gas and/or #6 low sulphur residual oil. Natural gas is received through the Iroquis Pipeline under Long Island Sound. All four units can operate simultaneously on natural gas unless restricted by system reliability. The station receives fuel oil deliveries from an offshore unloading facility and pumped to a tank farm on five tanks with capacity of two million barrels. Summer availability from 2003 to 2013 has averaged greater than 97%. The unit EFORd for the past 10 years has averaged below 3%.

Managed Systems				
Operations	Maintenance	Work Mgt	Spare Parts	Comments: Operations and maintenance procedures are in place. The maintenance work management system (CMMS) is used to identify, plan, schedule, document execution & maintain history for all DM&PM.
Financial Planning				
Base	Outage	Capital		Comments: The 2014 thru 2018 Capital Budget for the Northport Station is in excess o[redacted]
Material Condition/Major Systems				Comments: By 2015, fuel oil tanks 2&3 will have been cleaned and inspected, tank 5 has been cleaned, inspected and repaired and tank 1 upgrades will be completed. Tank 4 will be cleaned & inspected in 2017. Section 316b of the Federal Clean Wate Act could require cooling towers steam condensing for all Northport units which would require a significant capital expenditure (estimated a[redacted]. Permit has not been issued by NYSDEC and it is expected that a capital investment decision for cooling towers will be beyond the 5 year assessment period. DCS upgrade to NERC-CIP requirements in 2014.
Fuel Delivery	Forced Air	Environmental		
Service Water	Circ Water	Inst Air		
Service Air	Condensate	Feedwater		
Vacuum	Seal Stream	Water Treatment		
Extraction Steam	Elec Distribution	DCS		
Material Condition/Major Components				Comments: In 2012, turbine efficiency upgrade (GE Dense Pack) was installed for [redacted] and SOFA NOx reduction modification installed for [redacted] Reference Northport Boiler History in this report, Appendix 3.2, for extensive boiler background. South superheater header upgrade is budgeted for 2017. Stack muffler upgrade in 2016.
Turbines	Generators	Boilers		
Breakers	Transformers	Piping		
Stack				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention	Threatened without Minor Intervention	Yes	More than Adequate

National Grid Steam Station Units

Northport Unit 2

Executive Summary:
Northport Unit 2 is a 375 MWG unit placed in initial operation in June 1968. The unit is equipped with a GE turbine/generator and Combustion Engineering tangential fired steam boiler which will fire natural gas or #6 low sulphur residual oil. Summer availability from 2003 to 2014 has averaged greater than 97.5%. The unit EFORd for the past 10 years has averaged below 5%.

Managed Systems				
Operations	Maintenance	Work Mgt	Spare Parts	Comments: Operations and maintenance procedures are in place. The maintenance work management system (CMMS) is used to identify, plan, schedule, document execution & maintain history for all DM&PM.
Financial Planning				
Base	Outage	Capital		Comments: The 2014 thru 2018 Capital Budget for the Northport Station is in excess of [redacted]
Material Condition/Major Systems				Comments: Section 316b of the Federal Clean Wate Act could require cooling towers steam condensing for all Northport units which would require a significant capital expenditure (estimated at [redacted] Permit has not been issued by NYSDEC and it is expected that a capital investment decision for cooling towers will be beyond the 5 year assessment period. DCS upgrade to NERC-CIP requirements in 2014.
Fuel Delivery	Forced Air	Environmental		
Service Water	Circ Water	Inst Air		
Service Air	Condensate	Feedwater		
Vacuum	Seal Stream	Water Treatment		
Extraction Steam	Elec Distribution	DCS		
Material Condition/Major Components				Comments: In 2013, turbine efficiency upgrade (GE Dense Pack) was installed for [redacted] and SOFA NO× reduction modification installed for [redacted] Reference Northport Boiler History in this report, Appendix 3.2, for extensive boiler background. Rear ashpit tubing and side waterwall replacement in 2015 and rear waterwall replacement in 2014. Condenser retubing in 2015-2016.
Turbines	Generators	Boilers		
Breakers	Transformers	Piping		
Stack	Condenser			

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention | Threatened without Minor Intervention | Yes | More than Adequate

National Grid Steam Station Units

Northport Unit 3

Executive Summary:

Northport Unit 3 is a 375 MWG unit placed in initial operation in July 1972. The unit is equipped with a GE turbine/generator and Combustion Engineering tangential fired steam boiler which will fire natural gas or #6 low sulphur residual oil. Summer availability from 2003 to 2014 has averaged greater than 99%. The unit EFORd for the past 10 years has averaged slightly above 3%.

Managed Systems				
Operations	Maintenance	Work Mgt	Spare Parts	Comments: Operations and maintenance procedures are in place. The maintenance/work management system (CMMS) is used to identify, plan, schedule, document execution & maintain history for all DM&PM.
Financial Planning				
Base	Outage	Capital		Comments: The 2014 thru 2018 Capital Budget for the Northport Station is in excess of [redacted]
Material Condition/Major Systems				Comments: Section 316b of the Federal Clean Wate Act could require cooling towers steam condensing for all Northport units which would require a significant capital expenditure (estimated at [redacted] Permit has not been issued by NYSDEC and it is expected that a capital investment decision for cooling towers will be beyond the 5 year assessment period. DCS upgrade to NERC-CIP requirements in 2014.
Fuel Delivery	Forced Air	Environmental		
Service Water	Circ Water	Inst Air		
Service Air	Condensate	Feedwater		
Vacuum	Seal Stream	Water Treatment		
Extraction Steam	Elec Distribution	DCS		
Material Condition/Major Components				Comments: In 2010, turbine efficiency upgrade (GE Dense Pack) was installed for [redacted] and SOFA NO× reduction modification installed for [redacted] Reference Northport Boiler History in this report, Appendix 3.2, for extensive boiler background. Back pass tubing and lower side waterwall replacement and rear waterwall upgrade in 2016-2017. Stack muffler upgrade scheduled for 2016.
Turbines	Generators	Boilers		
Breakers	Transformers	Piping		
Stack				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Red	Yellow	White	Green
Not without Major Intervention	Threatened without Minor Intervention	Yes	More than Adequate

National Grid Steam Station Units

Northport Unit 4

Executive Summary:
Northport Unit 4 is a 375 MWG unit placed in initial operation in December 1977. The unit is equipped with a GE turbine/generator and Combustion Engineering tangential fired steam boiler which will fire natural gas or #6 low sulphur residual oil. Summer availability from 2003 to 2014 has averaged greater than 99%. The unit EFORd for the past 10 years has averaged below 4%.

Managed Systems				
Operations	Maintenance	Work Mgt	Spare Parts	Comments: Operations and maintenance procedures are in place. The maintenance work management system (CMMS) is used to identify, plan, schedule, document execution & maintain history for all DM & PM.
Financial Planning				
Base	Outage	Capital		Comments: The 2014 thru 2018 Capital Budget for the Northport Station is in excess of [redacted]
Material Condition/Major Systems				
Fuel Delivery	Forced Air	Environmental		Comments: Section 316b of the Federal Clean Wate Act could require cooling towers steam condensing for all Northport units which would require a significant capital expenditure (estimated at [redacted] Permit has not been issued by NYSDEC and it is expected that a capital investment decision for cooling towers will be beyond the 5 year assessment period. DCS upgrade to NERC-CIP requirements in 2014.
Service Water	Circ Water	Inst Air		
Service Air	Condensate	Feedwater		
Vacuum	Seal Stream	Water Treatment		
Extraction Steam	Elec Distribution	DCS		
Material Condition/Major Components				
Turbines	Generators	Boilers		Comments: In 2011, turbine efficiency upgrade (GE Dense Pack) was installed for [redacted] and SOFA NO× reduction modification installed for [redacted] Reference Northport Boiler History in this report, Appendix 3.2, for extensive boiler background. Pendant platen SH upgrade, economizer replacement and extended side waterwall upgrade in 2018.Stack muffler upgrade in 2017.
Breakers	Transformers	Piping		
Stack				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Red	Not without Major Intervention
Yellow	Threatened without Minor Intervention
White	Yes
Green	More than Adequate

National Grid Steam Station Units

Port Jefferson Unit 3

Executive Summary:
Port Jefferson Unit 3 is a 175 MWG unit placed in initial operation in 11/08/58. The unit is equipped with a GE turbine/generator and Combustion Engineering tangential fired steam boiler which will fire natural gas or #6 low sulphur residual oil. Natural gas burn is sometimes contrained by low gas system pressure. Summer availability from 2007 to 2014 has been greater than 98%. The unit annual EFORd for the past seven years has been below 2%. Port Jefferson Unit 3 has received a NYSDEC SPDES permit addressing the Section 316b Federal Clean Water Act and in progress this year installing circ. water pumps variable speed drives, fish friendly travelling screens, upgrade salt water booster pumps and vacuum priming systems.

Managed Systems				
Operations	Maintenance	Work Mgt	Spare Parts	Comments: Operations and maintenance procedures are in place. The maintenance work management system (CMMS) is used to identify, plan, schedule, document execution & maintain history for all DM&PM.
Financial Planning				
Base	Outage	Capital		Comments: The 2014 thru 2018 Capital Budget for the Port Jefferson Station is in excess of [redacted]
Material Condition/Major Systems				
Fuel Delivery	Forced Air	Environmental		Comments: Port Jefferson Station is in the process of testing and refurbishing its fuel oil storage tanks. No major environmental issues exist for this unit through the next five years. Modification addressing the NYSDEC SPDES permit for Section 316b Federal Clean Water Act are being installed this year. From 2015 to 2017, approximately [redacted] in capital improvements are scheduled for fuel unloading wharf & Bulkhead renovation.
Service Water	Circ Water	Inst Air		
Service Air	Condensate	Feedwater		
Vacuum	Seal Stream	Water Treatment		
Extraction Steam	Elec Distribution	DCS		
Material Condition/Major Components				
Turbines	Generators	Boilers		Comments: Factory Mutual Boiler Inspection in 2013 did not identify any major problems but noted pitting in the ashpit bend tubes; however, the age of the boiler piping and headers requires continual monitoring and replacements. Pendants and tube bundles have been replaced during the past ten years and National Grid will be replacing the unit's ashpit waterwalls in 2014 and LTRH replacement in 2016. As a result of a 2013 independent stack inspection, a capital improvement o[redacted] has been allocate this year for shell, liner and cap refurbishment.
Breakers	Transformers	Piping		
Stack				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Red	Not without Major Intervention
Yellow	Threatened without Minor Intervention
White	Yes
Green	More than Adequate

National Grid Steam Station Units

Port Jefferson Unit 4

Executive Summary:
Port Jefferson Unit 4 is a 175 MWG unit placed in initial operation in 11/11/60. The unit is equipped with a GE turbine/generator and Combustion Engineering tangential fired steam boiler which will fire natural gas or #6 low sulphur residual oil. Natural gas burn is sometimes contrained by low gas system pressure. Summer availability from 2008 to 2014 has been greater than 98%. The unit annual EFORd for the past six years has averaged below 3%. Port Jefferson Unit 4 has received a NYSDEC SPDES permit addressing the Section 316b Federal Clean Water Act and in progress this year installing circ. water pumps variable speed drives, fish friendly travelling screens, upgrade salt water booster pumps and vacuum priming systems.

Managed Systems			
Operations	Maintenance	Work Mgt	Spare Parts

Comments: Operations and maintenance procedures are in place. The maintenance work management system (CMMS) is used to identify, plan, schedule, document execution & maintain history for all DM&PM.

Financial Planning			
Base	Outage	Capital	

Comments: The 2014 thru 2018 Capital Budget for the Port Jefferson Station is in excess of [redacted]

Material Condition/Major Systems			
Fuel Delivery	Forced Air	Environmental	
Service Water	Circ Water	Inst Air	
Service Air	Condensate	Feedwater	
Vacuum	Seal Stream	Water Treatment	
Extraction Steam	Elec Distribution	DCS	

Comments: No major environmental issues exist for this unit through the next five years. Modification addressing the NYSDEC SPDES permit for Section 316b Federal Clean Water Act are being installed this year. From 2015 to 2017, approximately [redacted] in capital improvements are scheduled for fuel unloading wharf, bulkhead,catwalk and dolphins renovation.

Material Condition/Major Components			
Turbines	Generators	Boilers	
Breakers	Transformers	Piping	
Stack			

Comments: Factory Mutual Boiler Inspection in 2014 did not identify any major problems; however, the age of the boiler piping and headers requires continual monitoring and replacements. Pendants and tube bundles have been replaced during the past ten years and National Grid will be replacing the unit's HTRH and burner belt waterwall tubes in 2017.

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Red	Yellow	White	Green
Not without Major Intervention	Threatened without Minor Intervention	Yes	More than Adequate

National Grid Gas Turbine and Diesel Units

EFBarrett GT Station - 11 Units

Executive Summary:

This station consists of eleven (11) units. Units 1 through 8 (unit 7 is retired) are General Electric model Frame 5M units, each nominally rated at 18MW, initial operation date 1970. Units 9 through 12 are TP&M model FT4A9 units, each nominally rated at 42MW, intial operation date 1971. All units are dual fuel capable. There is one fuel oil storage tank on site, replenished via truck delivery. All units have inlet fogging systems for Power Recovery during extreme summer heat operation. This station is remote operated and manned. Recent Capital Improvements include new Digital Control Systems on Units 9-12 with plans to install same on units 1-8. Planned Capital Improvements include exhaust stack and elbow replacements, blade and vane replacements on Units 9-12, exhaust plenum replacements units 1-8. There are no known generator issues at this site, except as noted below. All units are well maintained and in good condition for continued operation.

Managed Systems				
Operations	Maintenance	Work Mgt	Spare Parts	Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
				The 2014 thru 2018 Capital Budget for this station is in excess of [redacted]
Base	Outage	Capital		
Material Condition/Major Systems				
Fuel Storage	Start Systems	Environmental		All Major Components are in satisfactory condition. Outward cosmetic appearance attention (painting) is required and planned for enclosures. Refer to Control System comments in Executive Summary above.
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				
Comb. Turbines	Compressors	Generators		All Major Components are in satisfactory condition. Units 9-12 exhaust stacks are scheduled for replacement in future years. GE TIL 1576 Rotor End of Life, is not a concern for Units 1-5 at this time. Units 6 and 8 may need to be inspected before 2019. See Report Section 3.4. Units 9-11 (U12 completed) generator fields require rotating cooling fan wheel replacements to prevent future in-service failure and stator damage.
Breakers	Transformers	Stacks		
Inlet ducts		Rotors		

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

	Not without Major Intervention		Threatened without Minor Intervention		Yes		More than Adequate

National Grid Gas Turbine and Diesel Units

East Hampton GT Unit (1) & Diesels (3)

Executive Summary:

This station consists of four (4) units. Unit 1 is a TP&M model FT4A-9, nominally rated 23MW, initial operation date 1970. Units 2,3 and 4 are GM diesel-generators model MP36, each nominally rated 2MW, initial operation date 1962. All units are liquid fuel fired only. There are two (2) fuel oil storage tanks on site, replenished via truck delivery. This station is remote operated and unmanned. Recent Capital Improvements include new Digital Control Systems on all units and Catalytic Converters with higher exhaust stacks for diesel emissions control on Units 2,3 and 4. Planned Capital Improvements include replacement of the RTU on Unit 1. There are no known generator issues at this site. The units at this site are generally maintained to a very high degree of readiness due to the local service area requirements during the summer peak load season (south fork of LI) and in good condition for continued operation.

Managed Systems				
Operations	Maintenance	Work Mgt.	Spare Parts	Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Financial Planning				
Base	Outage	Capital		The 2014 thru 2018 Capital Budget for this station is [redacted]
Material Condition/Major Systems				
Fuel Storage	Start Systems	Environmental		All Major Systems are in satisfactory condition. General cosmetic appearance (painting) attention is required and planned for enclosures. Refer to Control System comments in Executive Summary above.
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				
Comb. Turbines	Compressors	Generators		All Major Components are in satisfactory condition.
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention	Threatened without Minor Intervention	Yes	More than Adequate

National Grid Gas Turbine and Diesel Units

Glenwood GT Units (2-LM6000)

Executive Summary:

This station consists of two (2) units. Units 4 and 5 are General Electric model LM6000PC units, each nominally rated 45MW, initial operation date 2002. Both units are dual fuel capable. There is a fuel storage tank on site, replenished via truck delivery. These units have cooled water inlets for extreme summer operation power recovery, water injection for NOX control and ammonia injection for stack emissions control. This station is remote operated and manned. There are no planned Capital Improvement projects required at this station at present. There are no generator issues at this site. These units have not experienced the compressor blade HCF (High Cycle Fatigue) failures as have the Port Jefferson LM6000 units. However, the subject rows of blades have been replaced pro-actively and should be monitored going forward. These units are well maintained and in good condition for continued operation.

Managed Systems				Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Operations	Maintenance	Work Mgt	Spare Parts	
Financial Planning				There are no schedule Capital Improvement project planned for this station at this time.
Base	Outage	Capital		
Material Condition/Major Systems				Satisfactory.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				Satisfactory. As noted above, compressor blade HCF issues need to be monitored going forward. This issue is being addressed under OEM warantee.
Comb. Turbines	Compressors	Generators		
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention — Threatened without Minor Intervention — Yes — More than Adequate

National Grid Gas Turbine and Diesel Units

Glenwood GT Units (3)

Executive Summary:
This group consists of three (3) units at two (2) separate, but in close proximity, locations. Unit 1 is a General Electric model Frame 5L, nominally rated 16MW, initial operation date 1967. Units 2 and 3 are General Electric model Frame 7B units, each nominally rated 55MW, initial service dates 1972. All units are liquid fuel fired only. There are four (4) associated fuel storage tanks, replenished via truck delivery. These units are remote operated and unmanned. Scheduled and planned Capital Improvement projects include installation of Disturbance Monitoring Equipment and RTU replacement. There are no known generator issues associated with these units. All units are well maintained and in good condition for continued operation.

Managed Systems				Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Operations	Maintenance	Work Mgt	Spare Parts	
Financial Planning				The 2014 thru 2018 Capital Budget for these units is in excess of [redacted]
Base	Outage	Capital		
Material Condition/Major Systems				Satisfactory.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				Satisfactory. GE TIL 1576 Rotor End of Life, is not a concern for these units.
Comb. Turbines	Compressors	Generators		
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention

Threatened without Minor Intervention

Yes

More than Adequate

National Grid Gas Turbine and Diesel Units

Holtsville Generating Station - GT Units (10)

Executive Summary:

This station consists of ten (10) units. Units 1-5 are TP&M model FT4C-1 units, nominally rated 55MW each, initial operation date 1974. Units 6-10 are TP&M model FT4C-1D units, nominally rated 55MW each, initial operation date 1975. All units are liquid fuel fired only. Fuel is stored off-site at a leased tank facility and supplied via underground pipeline to the station. All units have Power Recovery Inlet fogging systems for operation during extreme summer heat conditions and water injection for NOX control (retro-fit). This station is remote operated and manned. Capitial Improvement projects recently completed include new Digital Control System installation (two units remain and in progress), and Disturbance Monitoring Equipment. Planned Capital Improvements include inlet plenum baffle replacement, selected stack replacement and exhaust elbow replacement. There are no known generator issues at this site. All units are well maintained and in good condition for continued operation.

Managed Systems				
Operations	Maintenance	Work Mgt	Spare Parts	Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Financial Planning				
Base	Outage	Capital		The 2014 thru 2018 Capital Budget for this station is in excess of [redacted]
Material Condition/Major Systems				
Fuel Storage	Start Systems	Environmental		Satisfactory. These units have recently been improved by adding water injection for NOx control. Refer to Control System comments in Executive Summary above.
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				
Comb. Turbines	Compressors	Generators		Satisfactory. Stacks and inlet ducts requiring attention are addressed in the Capital Projects five (5) year plan.
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention	Threatened without Minor Intervention	Yes	More than Adequate

National Grid Gas Turbine and Diesel Units

Port Jeff GT Units (2-LM6000)

Executive Summary:

This station consists of two (2) units. Units 2 and 3 are General Electric model LM6000PC units, each nominally rated 45MW, initial operation date 2002. Both units are dual fuel capable. There is a fuel storage tank on site, replenished via truck delivery. These units have cooled water inlets for extreme summer power recovery, water injection for NOX control and ammonia injection for stack emissions control. This station is remote operated and manned. There are no known Capital Improvement projects required at this station at present. There are no known generator issues at this site. There are some gas turbine compressor blades experiencing HCF (High Cycle Fatigue) failures which is under investigation and replacement with the OEM. This is a known industry-wide issue, not unique to this station. These units are well maintained and in good condition for continued operation.

Managed Systems				Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Operations	Maintenance	Work Mgt	Spare Parts	
Financial Planning				Satisfactory. There are no Capital Improvement projects planned for these units at the present time.
Base	Outage	Capital		
Material Condition/Major Systems				Satisfactory.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				Satisfactory.
Comb. Turbines	Compressors	Generators		
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

(red)	Not without Major Intervention	(yellow)	Threatened without Minor Intervention	(white)	Yes	(tan)	More than Adequate

National Grid Gas Turbine and Diesel Units

Port Jeff GT Unit (1)

Executive Summary:

This site consists of one (1) unit. Unit 1 is a General Electric model Frame 5L unit, nominally rated 16MW, initial operation date 1966. This unit is liquid fuel fired only. There is one (1) fuel storage tank on site, replenished via truck delivery. This unit is remote operated and unmmaned. This unit serves as the Black Start power source to the adjacent steam plant. There are no required Capital Improvement projects required or planned at the present time. There are no known generator issues at this site. This unit is well maintained and in good condition for continued operation.

Managed Systems				Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Operations	Maintenance	Work Mgt	Spare Parts	
Financial Planning				Satisfactory. There are no Capital Improvement projects planned for this unit at the present time.
Base	Outage	Capital		
Material Condition/Major Systems				Satisfactory.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				Satisfactory. GE TIL 1576 Rotor End of Life, is not a concern for this unit.
Comb. Turbines	Compressors	Generators		
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention

Threatened without Minor Intervention

Yes

More than Adequate

National Grid Gas Turbine and Diesel Units

Southampton GT Unit (1)

Executive Summary:

This site consists of one (1) unit. Unit 1 is a General Electric model Frame 5D, nominally rated 12MW, initial operation date 1963. This unit is liquid fuel fired only. There is one (1) fuel oil storage tank on site, replenished via truck delivery. This station is remote operated and unmanned. Recent Capital Improvement projects include installation of a new Digital Control System. There are no known generator issues at this site. The turbine rotor on this unit was replaced in 2011 with a refurbished unit due to End of Rotor Life concerns associated with GE TIL 1576. This unit is well maintained and in good condition for continued operation. This unit is famous as the first generator in-service, providing power to Long Island during the famous 1965 Northeast Blackout.

Managed Systems				Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Operations	Maintenance	Work Mgt	Spare Parts	
Financial Planning				The 2014 thru 2018 Capital Budget for this unit is in excess of [redacted]
Base	Outage	Capital		
Material Condition/Major Systems				Satisfactory. Outward cosmetic appearance (painting) attention is required and planned for enclosure. Refer to Control System comments in Executive Summary above.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				Satisfactory.
Comb. Turbines	Compressors	Generators		
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention	Threatened without Minor Intervention	Yes	More than Adequate

National Grid Gas Turbine and Diesel Units

Southold GT Unit (1)

Executive Summary:
This site consists of one (1) unit. This unit is a General Electric model Frame 5J unit, nominally rated 14MW, initial operation date 1964. This unit is liquid fuel fired only. There is one (1) fuel oil storage tank on site, replenished via truck delivery. This station is remote operated and unmanned. Recent Capital Improvement projects at this site include installation of a new Digital Control System. Future Capital Improvement projects include Remote Terminal Unit (RTU) replacement. There are no known generator issues at this site. The rotor in this unit was replaced in 2011, with the refurbished rotor from retired EFBarrett Unit 7, due to Rotor End of Life concerns with GE TIL 1576. This unit is well maintained and in good condition for continued operation.

Managed Systems				Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Operations	Maintenance	Work Mgt	Spare Parts	
Financial Planning				The 2014 thru 2018 Capital Budget for this unit is in excess of [redacted]
Base	Outage	Capital		
Material Condition/Major Systems				Satisfactory. General cosmetic appearance (painting) attention is required and planned for the enclosure. Refer to Control System comments in Executive Summary above.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				Satisfactory.
Comb. Turbines	Compressors	Generators		
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention	Threatened without Minor Intervention	Yes	More than Adequate

National Grid Gas Turbine and Diesel Units

Wading River Generating Station - GT Units (3)

Executive Summary:

This station consists of three (3) units. These units are General Electric model Frame 7E units, each nominally rated 90MW, initial operation date 1989. These units are liquid fuel fired only. There is one fuel oil storage tank on site, replenished via truck delivery. These units are equipped with water injection for NOX control. This station is remote operated and manned. Current/planned Capital Improvement projects include replacement of all exhaust stacks, fire protection bulk CO_2 storage tank replacement, Disturbance Monitoring Equipment installation, and turbine casing replacements (due to cracking). There are no known generator issues at this site. All units are well maintained and in good condition for continued operation.

Managed Systems				
Operations	Maintenance	Work Mgt	Spare Parts	Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Financial Planning				
Base	Outage	Capital		The 2014 thru 2018 Capital Budget for this station is in excess o[redacted]
Material Condition/Major Systems				
Fuel Storage	Start Systems	Environmental		Satisfactory. Replacement of bulk CO_2 storage systems planned as Capital Improvement.
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				
Comb. Turbines	Compressors	Generators		Satisfactory. Replacement of exhaust stacks currently in progress as Capital Improvement project.
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Red	Not without Major Intervention
Yellow	Threatened without Minor Intervention
White	Yes
Gold	More than Adequate

National Grid Gas Turbine and Diesel Units

West Babylon GT Unit (1)

Executive Summary:

This station consists of one (1) unit. This unit is a General Electric model Frame 7A unit, nominally rated 53MW, initial operation date 1971. This unit is liquid fuel fired only. There is one fuel oil storage tank on site, replenished via truck delivery. This station is remote operated and unmanned. Planned Capital Improvement projects include Remote Terminal Unit (RTU) upgrade and inlet duct replacement. There are no known generator issues on this unit. This unit is well maintained and in good condition for continued operation.

Managed Systems				
Operations	Maintenance	Work Mgt	Spare Parts	Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Financial Planning				
Base	Outage	Capital		The 2014 thru 2018 Capital Budget for this unit is in excess of [redacted]
Material Condition/Major Systems				Satisfactory.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				Satisfactory. Inlet duct replacement is a planned Capital Improvement project. GE TIL 1576 Rotor End of Life, is not a concern for this unit.
Comb. Turbines	Compressors	Generators		
Breakers	Transformers	Stack		
Inlet Duct				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Red	Not without Major Intervention
Yellow	Threatened without Minor Intervention
White	Yes
Gold	More than Adequate

National Grid Gas Turbine and Diesel Units

Shoreham GT Units (2)

Executive Summary:

There are two (2) units at this site. Unit 1 is a General Electric model Frame 7A unit, nominally rated 53MW, initial operation date 1971. Unit 2 is a TP&M model FT4A8 unit, nominally rated 19MW, initial operation date 1966. Both units are liquid fuel fired only. There is one (1) fuel oil storage tank on site, replenished via truck delivery. This station is remote operated and unmanned. Future Capital Improvement projects include new Digital Control System installation. There are no known generator issues at this site. These units are well maintained and in good condition for continued operation. (Note - Unit 1 has the distinction of being the first GE Frame 7 produced).

Managed Systems				Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Operations	Maintenance	Work Mgt	Spare Parts	
Financial Planning				The 2014 thru 2018 Capital Budget for this site is in excess of [redacted]
Base	Outage	Capital		
Material Condition/Major Systems				Satisfactory.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				Satisfactory. GE TIL 1576 Rotor End of Life, is not a concern for Unit 1.
Comb. Turbines	Compressors	Generators		
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

	Not without Major Intervention		Threatened without Minor Intervention		Yes		More than Adequate

APPENDIX 1

National Grid Gas Turbine and Diesel Units

Northport APG Unit

Executive Summary:

This site consists of one (1) unit. This unit is a General Electric model Frame 5L unit, nominally rated 16MW, initial operation date 1967. This unit is liquid fuel fired only. There is one (1) fuel oil storage tank on site, replenished via truck delivery. This site is remote operated and unmanned. This unit serves as the Black Start power source for the adjacent steam plant. There are currently no Capital Improvement projects planned for this unit. This unit is equipped with a new Digital Control System. There are no known generator issues with this unit. This unit is well maintained and in good condition for continued operation.

Managed Systems				Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Operations	Maintenance	Work Mgt	Spare Parts	
Financial Planning				There no Capital Improvement projects planned for this unit at this time.
Base	Outage	Capital		
Material Condition/Major Systems				Satisfactory. Refer to Control System comments in Executive Summary above.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				Satisfactory. GE TIL 1576 Rotor End of Life, is not a concern on this unit.
Comb. Turbines	Compressors	Generators		
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Rquirements As Planned and Financed through 2019

Not without Major Intervention	Threatened without Minor Intervention	Yes	More than Adequate

APPENDIX 1.2
Northport P.S. Units 1-4
Major Boiler Modification History
Description and Listing, Rev. 19

NORTHPORT P.S. UNITS 1 - 4
MAJOR BOILER MODIFICATION HISTORY
DESCRIPTION AND LISTING REV. 19

Description

General

Units 1, 2, 3 and 4 were originally duplicate 375 MW units, although the early designs considered coal firing. Various modifications over the years to the waterwalls (WW) and superheater (SH) sections have now resulted in the units being only similar. Units 1 and 3 fireball rotates counterclockwise while Units 2 and 4 are clockwise rotation. Units 3 and 4 were designed for low excess air (5%) firing as compared to Unit 1 and 2 which were designed for 11% excess air. The lower excess air designed units required larger surface economizers in order to maintain the same boiler exit temperatures. This was accomplished with a spiral finned economizer for Unit 3. Unit 4 was designed with a continuous straight finned economizer, but taller with more passes to maintain the same heating surface was Unit 3.

1960s - 1978

Units 1 and 2 were converted to balanced draft (I.D. fans) at the same time the mechanical cyclone collectors were replaced with an electrostatic precipitator for opacity emission control. Early operation resulted in extremely high SH temperatures and spray flow. Thus, a new intermediate spray station was installed in the division panel inlet links. Furthermore, Unit 3 was designed without the radiant front wall SH, however the spray flows were still too high. With its initial high sulfur oil firing and MgO fuel additive, the Unit 3 spiral finned economizer was susceptible to pluggage. This is why the Unit 4 economizer was designed taller without the spiral fins. Unit 4 was required to fire the more expensive low-low sulfur oil (0.7%) due to the environmental regulations at that time. Unit 4 was never fired as hard for economic reasons. Thus, this unit has experienced relatively few tube failures due to the age of the unit, cleaner fuel, and lower output factors.

<u>1979 - Mid 1980s</u>

The Unit 3 front pendant spaced SH was shortened in the form of a "T" section to reduce SH sprays. This modification was unsuccessful as it resulted in failures in the intermediate pendant spaced SH region. The Unit 3 pendant platen SH section was replaced, upgrading the T1 tubing to T11 and the T11 tubing to T22. The inner hairpin tube was upgraded to 347H stainless steel. Some of the DMWs located in the outlet of the intermediate pendant spaced SH were replaced. The Unit 1 WW straight tubing only in the burner belt region from elevation 73' to 125' was replaced with in-kind material. Unit 3 was the only unit where the straight and burner corner tubing was replaced.

<u>Late 1980s</u>

Units 1, 2 and 3 conversion to permit operational fuel changes from high to low sulfur oil firing started in 1973, with the sole firing of 1.0% low sulfur fuel oil for these units occurring in 1988. Sprays continued to be too high on these units resulting in further tube failures. The System Needs Analysis Program (SNAP) was initiated with ABB/CE to improve operation and availability of Units 1-4. Unit 4 was instrumented and extensive boiler testing/modeling was performed. Unit 1 WW circulation testing was also performed. The following conclusions were drawn from the Units 1 and 2 WW study: (a) the full load data with all feedwater heaters in-service shows measured downcomer temperatures at values higher than expected with little subcooling. The lack of subcooling results in a reduction in the total design circulation system flow, (b) at full load, a number of circuits located at the quarter points of the front wall from elevations 110' to 124' and a portion of the upper rear arch/rear wall exhibit a potential for departure from nucleate boiling (DNB), and (c) with the removal of the radiant front wall, the WW surface exposed will absorb approximately 10% more of the total heat as compared to the existing furnace. The recommendation for the use of front WW rifled tubing will reduce the flow required in the front WW by 30%, which would permit more cooling water for the side and rear waterwalls. Due to reduced slagging from the low sulfur oil and waterwall tube blistering, <u>interim</u> re-orificing was performed on Units 1 and 2 to put more flow through the marginal circuits. The permanent re-orificing was performed in the early 1990s. Other SNAP implemented modifications intended to reduce sprays and improve unit reliability are listed in the next section.

Units 1 & 2 ash pit tubing was replaced during the 1987-1990 period. The work scope for the #1 and #2 front ashpit included 240 T11 tubes from elevation 45' to about 8' from the lower front mud drum, replacement of 40 front ashpit slope tubing on each end from elevation 45' to 58', and replacement of the 220 north and south side wall tubing from 3 feet above to 3 feet below the slope. The scope for the rear ashpit was similar to the front except only 20 tubes were replaced on each end from elevation 45' to 58'. During the Fall 2007 outage, #2 rear work includes the horizontal run from the GR duct to the rear mud drum nipple. Other possible lower priority work for #1 & #2 is the center tubes on the upper front & rear slopes, a portion of the horizontal rear tubing and the 10' foot spools back to the lower front drum.

Unit #3 rear ash pit tubing major work was replaced during the 1988-1989 period, although the spools to the rear drum was completed in 1996. The work scope accomplished was similar to Units 1 &2, except that the #3 rear ash pit tubing was replaced back to the drum. The higher priority work remaining for #3 is the front ashpit tubing which is scheduled for the fall 2009 outage.

Unit 3's overhaul in the late 1989 included the following; replaced the entire burner belt tubing due to corrosion fatigue and caustic gouging. The upper cut line elevation was 119'. The lower cut line for the front, rear and side waterwalls is elevation 85', except for the burner corner tubing which had a cut line at elevation 74'. The material was upgraded to T11. Further work included removing the lower tubing section that comprised the "T" section of the front pendant spaced SH and restoring it to its original configuration. During this "T" section modification, the materials of the outer two tubes were upgraded to T22. The first loop of the intermediate pendant spaced SH was shortened to reduce spray flows. Due to the limited time and budget, no replacement/material upgrades in this or other SH sections was performed.

<u>Early 1990s</u>

Implemented the majority of the SNAP recommendations for Unit 2 in 1992 as follows; removal of the radiant front wall SH and front waterwalls from below the burners (El. 86') to the front WW outlet header. Replaced front WW with rifled tubing from elevation 86' to the outlet header and re-orificed the lower front and rear drums. The upper rear arch nose tubing was replaced, going from 2" O.D. pegged fins to 2.5" O.D. membrane panels. Fourty-two (42) adjacent side wall tubes were replaced from elevation 128'-0" to 152'-9" on both north and south sides. Removal of the radiant front wall SH required in the installation of a new roof junction inlet header and relocation of the intermediate desuperheater spray station from the inlet to outlet of the division panels. This relocation was necessary because it would be useless to spray right after the drum since the steam is saturated. Redesign of the desuperheater liners included relocation of the penetration set screw from the middle to upstream portion to allow for thermal growth. The mounting pads were also upgraded to stellite material. The steam drums were modified from 2 to 4 rows of dryers which matches the Unit 3 and 4 designs. Further enhancements included the upgrade from slot to propeller type primary separators and from corrugated plate to dish type secondary separators. The Unit 2 pendant platen SH was replaced with material upgrades. These upgrades included changing the T1 to T11 and the T11 to T22. The inner hairpin and wrapper's tube lower portion was upgraded to stainless steel. The Unit 2 intermediate pendant spaced SH was fully replaced. This included material upgrades from T11 to T22 and extending back the 347H stainless steel portion, replacement of all DMW in its outlet, and surface reduction to the second loop to reduce sprays. The only major SNAP recommendation that was not implemented was increasing surface in the horizontal reheater to help make the required 1005F reheat steam temperature. Since this mod was not implemented, burner tilts and gas recirculation (GR) fan operations are used to raise the reheat steam temperature. However, there is limit to its effectiveness since higher GR flow and tilts also raises the SH sprays. Resized windbox/burner buckets and added close coupled overfire air (CCOFA) for NOx control. The CCOFA buckets were equipped with manual horizontal YAW adjustment. Removed bricking in the auxiliary air compartments. After start-up, it was initially difficult to achieve main steam temperature because the furnace was not "seasoned".

Mid-Late 1990s

Unit 4 was the first unit converted to natural gas firing in 1993. Due to higher convective flue gas temperatures and resulting higher tube metal temperatures experienced during gas firing, superheater modification were performed. This included the replacement of the front and intermediate pendant spaced SH. The T11 material was upgraded to T22, the surface was reduced in the second loop of the intermediates to reduce sprays, and all DMWs in the furnace (intermediate outlet) were replaced. The design of the Unit 4 intermediates was the same as Unit 2. Unit 4 burner mods included removing the bricking in the auxiliary air compartments, re-sizing of the burner buckets, adding CCOFA with Yaw. The pendant platen remained original.

For Unit 3 in 1996, the lower rear ashpit was replaced along with horizontal tubing back to the rear drum nipples.

For Unit 1, the SNAP modification was implemented in 1994 followed by the addition of gas firing capability in 1998. During the Unit 1 SNAP modifications, some front and rear P.S. superheater assemblies and selective individual tubing were replaced due to previous failures. The Unit 2 SNAP work was implemented in 1992 followed with additional of gas firing in 1995. The few implemented boiler modification differences performed on Unit 1 as compared to Unit 2 are shown in the Listing of Modifications. It should be noted that all burner buckets on all four Units are now the same size and design resulting in one set of spare parts. This is true even on Unit 3 where partial gas firing was added later.

<u>2000-2003</u>

During the Spring 2000 outage, Unit 2 has several major modifications as follows: (a) The front pendant spaced SH was replaced with upgraded tubing due to the high metal temperature experienced during gas firing (along with selective intermediate and rear tubing). The design of these #2 fronts will be the same as Unit 4. Unit 1 would then be the only gas fired Unit without the fronts upgraded. (b) All four burner corner tubing panels were replaced from elevation 63'-5" to 128'-1". Each burner corner included 16 corner, 4 side wall, and 10 front or rear tubing. The burner corner tubing was upgraded from A210-A1 to T11. (c) The roof tube support system was modified due to tube bowing and casing/refractory overheating, particularly on the North side. The cause of this problem was the rigid junction between the front waterwall and the roof tubing that prevented thermal growth. This modification removed the refractory at this junction, added new roof tube support members, replaced some pegged finned roof tubing, and the added of an expansion fold in the casing to allow thermal growth between the roof tubing and front waterwall.

During the Unit 2 Winter 2001 outage, the top "U" loop spools were replaced on the east side of the economizer. This consists of Rows 1 and 2 at the economizer outlet. This was performed to due cracks at the fin to tube junction. To improve the design, the fins were cut-back and beveled on a 45 degree angle to reduce the stress. Since there are 22 rows in the vertical direction, this modification was considered a temporary fix until a full replacement could be implemented in the future.

During the Unit 3 Spring 2001 outage, the DMW's for the outer tube row between the intermediate and rear pendant spaced superheater was replaced. Since there are 3 tubes in each assembly, then 33% of these in-furnace DMW's was replaced. Furthermore, all of DMW's in the rear pendant spaced SH, which are located in the penthouse, were replaced.

During the Unit 1 Fall 2001 outage, the following modifications were implemented: a) the remainder of the penthouse DMW's located in the rear pendant spaced superheater outlets were replaced. This included 118 flow restrictors designed by Aptech Engineering, Inc. which was intended to balance the tube metal temperatures, b) the top rows 1&2, east side, of the economizer were replaced with spools, and c) the roof tube mods were performed with casing work on both north and south sides .

During the Unit 2 Spring 2002 outage, an upgraded roof tube support modification was implemented using inconnel bar located between the north side wall and the first roof tube. This higher grade material was utilized since the year 200 mod experienced overheating.

During the Unit 3 Fall/Winter 2002 outage, replacement of the horizontal reheater and economizer was implemented. The existing staggered spiral finned economizer was replaced with an in-line spiral fin to prevent ash pluggage. This economizer design consisted of 107 assemblies - two tube intermesh with a fin pitch of 2.5, one economizer inlet, one economizer outlet header, six new Clyde Bergemann sootblowers, and selected replacement of lower support steel. The new economizer support utilized an improved ladder support design. The reheater design consisted of 119 assemblies, one inlet header, and forty-two hanger tubes to replace previous cut and plugged circuits. The reheater utilized an improved slip spacer tube support design. The economizer/reheater modification also includes new flow baffles, sonic baffles, and vibration snubbers. New steam cooled wall tubing panels were provided for the south side. Seventy tubes were provided for this south wall. An overall boiler efficiency improvement of more than 1% is expected by these modifications.

Although the restoring of the plugged tubes will help make design reheat steam temperature, additional reheat surface as compared to the original design was not implemented for the following reasons: 1) The surface reduction in the intermediate pendant spaced SH aimed at reducing SH sprays during the SNAP program raises the flue gas temperature to the RH. This results in increasing the RH steam temperature 15-20 degrees. 2) The combustion staging related to the installation of CCOFA raises the furnace exit gas temperature about 40F which contributes to a 2-3 degree rise in RH steam temperature. 3) Recent regulations/concerns of Opacity exceedences results in operating, at times, with slightly higher excess O2 levels. This increased flue gas weight has a small effect on raising RH steam temperature. During this outage, the top two tiers were modified for gas capability. New ignitors were installed for all tiers.

<u>2004-2006</u>

During the Spring 2004 outage, the #2 continuous fin economizer was replaced with a new in-line spiral fin economizer. This economizer design consisted of 107 assemblies - two tube intermesh, one economizer inlet and one economizer outlet header. The Unit #2 economizer design was more conservative than #3 since the fin pitch was enlarged to 2.0 and no sootblowers were installed. The platforms at elevation 113' & 133' were only installed on the North side for access purposes only. The North side roof tubes were re-designed, consisting of the outer 12 tubes along with thicker fins and narrower tube spacing. The casing side wall stirrup bolts were replaced to prevent wall movement.

During the Fall 2004 Unit #3 outage, the intermediate pendant spaced SH was upgraded/replaced along with full mating 13 front and 21 rear pendant spaced assemblies. This new #3 intermediate SH design is now similar to Units 1, 2 and 4. New in-furnace DMW's were supplied with the new intermediates. The upper rear arch was replaced with a solid fin instead of the original pegged fin design along with adjacent north & south side wall and extended side wall tubes. Other replacements consist of one new pendant platen assembly (assembly #6 from the south), 31 front waterwall tubes (near C2) and 102 north side waterwall tubes. The front wall tubes are #27 thru #57, elevation 95'-110'. The north side wall tubes begin with the first straight tube near C4 at platform elevation 61'. Also, removal of the obsolete RH spray stations and piping was performed.

For Unit #1 during the fall 2005 outage, there was four major boiler work scopes was follows: (A) Replacement/upgrade of the economizer with the same fin pitch design as #1. (B) Replacement and upgrade of the tubing for all four burner corners. This scope includes the burner corner tubing plus 4 straight sidewall tubes and 10 straight front & rear tubes from elevation 128'-1" to elevation 63'-5". The only exception the front wall tubing form elevation 122'-1' to 128'-1" where there was existing rifled tubing. (C) Replacement and upgrade of tubing for selected Division Panel SH tubing. As measured from south to north; #1F - wrapper tube only, #3F & 3R, 4F & 4R - wrapper and hairpin; #2R – outer two tubes and hairpin. (D) Modification of roof tubes on south side, similar scope to Unit #2 north. (E) R&D project was implemented for two air cooled oil guns. Only one new burner at tier 9, corner 1 was initially put into service.

<u>2007-2008</u>

For Unit #3 during the Spring 2007, the north and south side waterwalls were replaced/upgraded with T11 tubing material. The new work scope starts below where the 1989 tube replacement stopped. On the south side, the work scope is one hundred-eighty (180) side wall tubes from elevation 85'-3" to 68'-3" plus 5 straight tubes in C2 & C3 from elevation 74'-3" to 68'-3". On the north side, the work scope is 180 side wall tubes from elevation 85'-3" to 68'-3" plus 5 straight tubes in C1 from elevation 74'-3" to 68'-3". The straight tubes on the northwest wall extending towards C4 were replaced during the 2004 upper rear arch replacement. This was replaced since this the material access region. The first 43 tubes were replaced down to elevation 66'-2". The next 59 tubes were replaced down to elevation 62'-2". Another work scope, due to thermal cracking, was re-design/replacement of the end four (4) steam drum SH connecting nozzles on both ends with expansion cups.

For Unit #2 during the fall 2007, there was three boiler work scopes implemented: (A) Due to overheating, the roof tube modification were completed where the outer 12 tubes on the south side (adjacent to the Div. Pnls) was redesigned with reduced tube spacing, thicker and higher grade membrane materials. Tube length is 26'-2 7/8". The work scope was extended an additional 13'-9 3/8" feet towards the west for these 12 tubes on both the north and south sides. New refractory and casing was installed. (B) Selective replacement of the division panel tubing as follows: 1F - Outer two tubes & hairpin, 1R - Outer two tubes & hairpin, 2F - Outer two tubes & hairpin, 2R - Outer two tubes & hairpin, 3F: Outer two tubes & hairpin and inner tube, 3R - Outer six tubes & hairpin, 4F- Outer two tubes & hairpin, 4R - Outer two tubes & hairpin. (C) Replacement of the 180 lower rear spools. This work scope starts at the lower rear mud nipples and extending 9-1/2" into the back wall of the gas recirculation duct. Spool length is 2'-7 1/2". One hundred-fifty-two (152) of these tubes tube are panelized to include the duct wall plating with the tubes. These panels are as follows: (16) - 9 tube grouping, (2) - 6 tube grouping and (1) - 2 tube grouping.

For Unit #3 during the Spring 2008, there was four work scopes to be implemented: (A) The front waterwalls replacement/upgrade with T11 tubing material. The work scope consists of one hundred & ninety-eight (198) tubes from elevation 85'-3" to 62'-9" which is 22'-6" height plus twenty-seven (27) straight tubes each in the C1 & C2 from elevation 74'-3" to 62'-9" which is 11'-6" height. Total 252 tubes are being replaced. (B) Re-design/replacement of the end four (4) steam drum SH connecting nozzles on both ends with expansion cups. (C) Gas capability for the lower two tiers will be implemented. (D) Upgrade of the Northport ID Inlet damper & expansion joint assemblies. Total 2 assemblies. Damper upgrade from parallel to opposed blade design.

For Unit #1 during the fall 2008 outage, the work scope consists of the upgrade of the 59 front pendant spaced superheater assemblies from T11 to T22, Also due to previous tube failures, the scope includes the in-kind replacement of 5 intermediate & 5 rear assemblies plus five outer tubes on other intermediate & rear assemblies.

<u>2009-2012 (SOFA Outages)</u>

During the Unit #3 Fall 2009 outage, two boiler tube projects were performed:

1) In support of the separated overfire air (SOFA) work scope, replacement of four burner corner tube panels is required. Each tube panel is 18 tubes plus one loose tube on end for ease of field alignment. Total 20 tubes per corner. Tubing is 1-3/4" OD x 0.188"MWT x SA-213 T11 material. Tube panel contain suitable offset to accommodate the corner firing equipment/arrangement. New panels were installed from elevation 117'-9" to 128'-6'.

2) The lower front ashpit was replaced. This work scope consists of replacing 240 front ashpit tubes. The tubing is supplied in panels as follows:

- 22 tube panels – quantity (1)
- 20 tube panels – quantity (8)
- 19 tube panels – quantity (2)
- 10 tube panels – quantity (2)

Tubing is 1-3/4" OD x 0.188"MWT x SA-213 T11 material except the lower bifurcates which are 2-1/4" x 0.220"MWT x SA-213 T11. These larger diameter tubes are located on the outer 5 tubes on each end. Total tube panel length is approximately 23.5 foot long, of which approximately 16'-3' is located on the horizontal section and approximately 7'-3' bent to form the lower portion of the slope.

During the Unit #4 Fall 2010 outage, one boiler tube projects was performed.
In support of the separated overfire air (SOFA) work scope, replacement of four burner corner tube panels is required. Each tube panel is 18 tubes plus one loose tube on end for ease of field alignment. Total 20 tubes per corner. Tubing is 1-3/4" OD x 0.188"MWT x SA-213 T11 material. Tube panel contain suitable offset to accommodate the corner firing equipment/arrangement. New panels were installed from elevation 117'-9" to 128'-6'.

During the Unit #1 Fall 2011 outage, one boiler tube projects was performed.
In support of the separated overfire air (SOFA) work scope, replacement of four burner corner tube panels is required. Each tube panel is 18 tubes plus one loose tube on end for ease of field alignment. Total 20 tubes per corner. Tubing is 1-3/4" OD x 0.188"MWT x SA-213 T11 material. Tube panel contain suitable offset to accommodate the corner firing equipment/arrangement. New panels were installed from elevation 117'-9" to 128'-6'.

During the Unit #2 Fall 2012 outage, one boiler tube projects was performed.
In support of the separated overfire air (SOFA) work scope, replacement of four burner corner tube panels is required. Each tube panel is 18 tubes plus one loose

tube on end for ease of field alignment. Total 20 tubes per corner. Tubing is 1-3/4" OD x 0.188"MWT x SA-213 T11 material. Tube panel contain suitable offset to accommodate the corner firing equipment/arrangement. New panels were installed from elevation 117'-9" to 128'-6'. This completes the SOFA modification on all units. Also, the ID inlet dampers & expansion joints were upgraded. This completes these dampers & expansion joint assembly modification on all units. The GR inlet & outlet dampers and expansion joint assemblies were replaced/upgraded. This is the first unit to have the GR dampers & expansion joints replaced/upgraded.

2013-2014

During the Spring 2013 outage, the North superheater outlet header was replaced. The new header is 21-1/4" O.D. x 4.25" thick, A-335 Gr. P22 material. Specific components associated with this new header are as follows: 178 tube nipples, two header girth welds, one at the center and the other at end cap, one - Outlet 90 degree elbow, one - 5" connection for the safety valve, one - 2" connection for the drain. The one original - 3/4" vent connection is no longer needed.

During the Spring 2014 outage, the rear waterwalls were replaced. The work scope is the replacement of the 252 original rear waterwall tubing from elevation 128' to 64'. The existing tubing 1-3/4" OD x 0.188" MWT carbon steel tubing material was upgraded to 1-3/4" OD x 0.188" MWT T11 chrome-moly. Tubes are on 2-1/4" centers. In addition, 9 future wall blower tube offset openings at elevation 67'-6" on the rear (west) and north walls were also replaced. Each location consisted of 6 tubes - 24" long. The remaining 9 wall blower tube offsets on the south (4) and front/east (5) will be replaced during a future outage.

LISTING OF NORTHPORT MODIFICATIONS - SUMMARY				
	UNIT #1	UNIT #2	UNIT #3	UNIT #4
INSTALLATION OF INTERMEDIATE SPRAYS	YES	YES	YES	YES
ISOLATION OF REHEAT SPRAYS	YES	YES	YES	YES
CONVERSION TO BALANCED DRAFT	YES	YES	NA	NA
INSTALLATION OF REHEAT SONIC BAFFLES	YES	YES	YES	YES
REPLACEMENT OF HORIZONTAL REHEATER	NO	NO	YES	NO
ECONOMIZER SUPPORT REPAIR	YES	YES	YES	NO
REPLACEMENT OF BURNER CORNERS WW	YES	YES	YES	NO
INSTALLATION OF SOFA TUBE PANELS	YES	NO	YES	YES
REPLACEMENT OF FRONT WW	NO	NO	PARTIAL	NO

REPLACEMENT OF SIDE WW	NO	NO	PARTIAL	NO
REPLACEMENT OF REAR WW	NO	YES	NO	NO
REMOVAL OF RADIANT FRONT WALL	YES	YES	NA	NA
INSTALL ROOF TUBE INLET HEADER	YES	YES	NA	NA
INSTALL FRONT WW RIFLED TUBING	YES	YES	NO	NO
RE-ORIFICE LOWER WW DRUMS	YES	YES	NA	NA
RELOCATION OF INTERMEDIATE SPRAYS	YES	YES	YES	NO
REDESIGN OF INTERM. DESH LINERS	YES	YES	NO	NO
MODIFY STEAM DRUM DRYER ROWS	YES	YES	NO	NO
STEAM DRUM NOZZLE EXPANSION CUPS	NO	NO	PARTIAL	PARTIAL
REPLACEMENT OF PENDANT PLATEN SH	UPGRADE	UPGRADE	UPGRADE	NO
REPLACEMENT OF INTERM. P.S. SH	UPGRADE	UPGRADE	UPGRADE	UPGRADE
REPLACEMENT OF FURNACE DMW	100%	100%	100%	100%
REPLACEMENT OF PENTHOUSE DMW	100%	100%	100%	NO
REPLACEMENT OF FRONT P.S. SH	UPGRADE	UPGRADE	13 ASS'BLY	UPGRADE
REPLACEMENT OF REAR P.S. SH	5 ASS'BLY	TUBING	21 ASS'BLY	NO
REPLACEMENT OF DIVISION PANELS	PARTIAL	NO	NO	NO
REPLACEMENT OF UPPER REAR ARCH /WW	YES	YES	YES	NO
REPLACEMENT OF LOWER REAR ASHPIT/SIDE WW	YES	YES	YES	NO
REPLACEMENT OF LOWER FRONT ASHPIT/SIDE WW	YES	YES	YES	NO
REPLACEMENT OF HORIZONTAL REHEATER	NO	NO	YES	NO
REPLACEMENT OF ECONOMIZER	YES	YES	YES	NO
MODIFY ROOF TUBE SUPPORT	YES	YES	N.R.	N.R.
MODIFY ROOF TUBE DESIGN, 12 TUBES	SOUTH	N & S	NO	NO
WINDBOX RE-SIZING FOR CCOFA	YES	YES	YES	YES
INSTALLATION OF SOFA	YES	YES	YES	YES
INSTALLATION OF GAS SPUDS, 4 TIERS	YES	YES	YES	YES
ID INLET DAMPERS & EXP. JT	YES	YES	YES	YES
GR INLET/OUTLET DAMPERS & EXP. JT	NO	YES	NO	NO
SUPERHEATER OUTLET HDR - NORTH	YES	NO	NO	NO

Listing of Boiler Modifications

Unit No. 1

Conversion to Balanced Draft and Precipitator Installation – 1976
Installation of the Intermediate Desuperheater Sprays at Div. Panel Inlet - 1981
Isolation of Reheat Sprays - 1981
Economizer Support System Re-design -1986
Installation of Sonic Baffles in Horizontal Reheater - 1986
Replacement of Straight Tubes in Burner Belt – 1986
Replacement of lower front & rear ashpit tubing and intercept side wall panels - 1989

SNAP -1994

Removal of Front Radiant Superheater and Front Waterwalls
Installation of Roof Tube Inlet Header
Installation of Front Waterwall Rifled Tubing
Re-orificing Lower Waterwall Drums
Relocation of Intermediate Desuperheater to Div. Panel Outlet
Redesign of Intermediate Desuperheater Liners/Set Screw Location
Modify Steam Drum from 2 to 4 rows of Dryers & Re-design of Separator
Replacement of Pendant Platen Superheater & Water Cooled Spacer
Replacement/Surface Reduction of Intermediate Pendant Spaced SH, along with Replacement of all Dissimilar Metal Welds at its Outlet
Selective Replacement of Front & Rear Pendant Spaced SH Tubing
Replacement of Upper Rear Arch and adjacent side walls
Partial Replacement of Division Panels, #1 Front and rear, #2 Front
Windbox Re-sizing for CCOFA and New Buckets for NOx Control - 1994
Installation of Gas Spuds & Gas Ignitors - 1998
Replacement of Lower Rear & Front Ashpit and Interface Side Walls - 1998
Replacement of 48% of the DMWs at Outlet of Rear P.S. SH - 1998
Replacement of 52% of the DMWs at Outlet w/Flow Restrictors - 2001
Replacement of Economizer Spools - Rows 1 & 2, and Support Repairs – 2001
Modification to Roof Tube Support - 2001
Re-design of Economizer and South Roof Tubes - 2005
Replace Burner Corner/Adjacent Straight Waterwall Tubing - 2005
Replace Selected Division Panel SH Tubing - 2005
Upgrade Front Pendant Spaced Superheater and selected intermediate & rear assemblies/tubing- 2008
Four (4) SOFA Corner Tube Panels – 2011
ID Inlet Damper & Expansion Joint Assemblies – 2011
Superheater Outlet Header, North - 2013

Unit No. 2

Same as Unit No. 1 except no Burner Belt & no Div. Panel Tube Replacements, and no Economizer Support Re-design, 1992 & 1995
Full Replacement all DMWs in the Outlet of Rear P.S. SH (penthouse) – 1995
Installation of Gas Spuds & Gas Ignitors - 1995
Replacement of front/rear lower ashpit tubing and intercept side wall panels - 1990
Replacement/Upgrade of Front Pendant Spaced Superheater - 2000
Selective Intermediate & Rear P.S. SH Tubing - 2000
Replacement of 4 Burner Corner Tubing Panels - 2000
Modification to Roof Tube Support - 2000
Replacement of Economizer Spools - Rows 1 & 2, and Support Repairs - 2001
Re-design of Economizer and North Roof Tube - 2004
Partial Division Panel Replacement - 2007
Lower Rear Spools, Mud Drum thru GR Duct - 2007
Roof Tube Modification, North & South – 2007
Four (4) SOFA Corner Tube Panels – 2012
ID Inlet Damper & Expansion Joint Assemblies - 2012
GR Inlet/Outlet Damper & Expansion Joint Assemblies – 2012
Rear Waterwalls, Elevation 128' to 64' - 2014

Unit No. 3

Isolation of Reheat Sprays - 1973
Installation of the Intermediate Desuperheater Sprays at Div. Panel Outlet - 1979
Replacement of Pendant Platen Superheater & Water Cooled Spacer - 1979
Replacement with "T" section, lower 15' of Front Pendant Spaced SH - 1989
Replacement of Straight Tubes and Burner Corner Panels in Burner Belt - 1989
Surface Reduction only of First loop of Intermediate Pendant Spaced SH - 1989
Windbox Re-sizing for CCOFA and New Buckets for NOx Control - 1995
Replacement of Lower Rear ashpit back to Drum and Interface Side Walls, 1996
Replacement of 33% DMW between Intermediate and Rear Pendant Spaced SH - 2001
Replacement of 100% DMW in penthouse for Rear Pendant Spaced SH – 2001
Redesign of Economizer - 2002
Replacement of Horizontal Reheater – 2002
Installation of Gas Spuds for Top 2 tiers & Gas Ignitors for 4 Tiers – 2002
Replacement/Upgrade of the Intermediate Pendant Spaced Superheater and mating 13 Front and 21 Rear assemblies. All in-furnace DMW's are new with the new intermediates – 2004/2005
Replacement of Upper Rear Arch, adjacent Side walls and Extended Side Walls – 2004/2005

Replacement/Upgrade of North & South Side WWs below the burner zone - 2007
Replacement/Upgrade of Front Waterwalls below the Burner Zone - 2008
Modify Steam Drum's SH Connecting Nozzles, Total 8 - 2008
Upgrade North ID Fan Inlet Damper/Expansion Joint Assemblies - 2008
Install gas spuds on lower Two Tiers for Full Gas Firing Capability - 2008
Front Ashpit, 240 tube, replacement, no adjacent side waterwall tubes - 2009
Four (4) SOFA Corner Tube Panels – 2009
ID Inlet Damper & Expansion Joint ssemblies – 2008 &2009

Unit No. 4
Isolation of Reheat Sprays - 1980
Installation of the Intermediate Desuperheater Sprays at Div. Panel Outlet - 1980
Replacement/Surface Reduction of front and Intermediate Pendant Spaced SH,
along with Replacement of all Dissimilar Metal Welds at its Outlet - 1993
Windbox Re-sizing for CCOFA and New Buckets for NOx Control - 1993
Installation of Gas Spuds & Gas Ignitors – 1993
Modify Steam Drum's SH Connecting Nozzles, Total 8 - 2006
Four (4) SOFA Corner Tube Panels – 2010
ID Inlet Damper & Expansion Joint Assemblies - 2010

Main References:
Work Order Files
SNAP and Gas Firing Reports
ABB/CE Inspection Reports/drawings
ABB/CE Instruction Manuals

Prepared By: D. M. Gordon

Rev. 0 - 3/3/99
Rev. 1 - 6/15/01
Rev. 2 - 11/22/01
Rev. 3 - 12/13/01
Rev. 4 - 9/19/02
Rev. 5 - 3/14/03
Rev. 6 - 4/9/03
Rev. 7 - 4/7/04
Rev. 8 - 9/7/04
Rev. 9 - 3/8/05
Rev. 10 - 11/24/05
Rev. 11 - 5/30/06
Rev. 12 - 1/3/08

Rev. 13 - 9/25/08
Rev. 14 - 10/6/09
Rev. 15 - 11/22/10
Rev. 16 - 6/17/11
Rev. 17 - 4/12/12
Rev. 18 - 8/9/13
Rev. 19 - 8/19/14

APPENDIX 1.3

List of Documentation Provided by National Grid

APPENDIX 1.3

LIST OF DOCUMENTATION PROVIDED BY NATIONAL GRID

1. **Corporate Documentation**
   a. National Grid Generation Units PSEG June 2014
   b. National Grid Fleet Asset Management for PSEG August 2014
   c. PSA Annual Performance Report 2012
   d. National Grid Letter to LIPA with 2014 thru 2018 Capital Budget
   e. CY2014 Generation CAPEX with PNs – LIPA submittal 10-24-13
   f. CY2014 to CY2018 Generation CAPEX –LIPA submittal 10-24-13
   g. PPO Safety Governance Committee Descriptions
   h. PPO Safety Initiatives and Statistics
2. **E.F. Barrett Power Station Documentation**
   a. EFB #2 Riggio EVC Testing of Safety Valves
   b. Boiler Tube Outages
   c. PSEGLI Presentation Info.ppt
   d. EFB NERC GADS Tests, Reserve Shutdown, Condenser Cleanings
   e. EFB NERC GADS Planned Outages, Forced Outages
   f. EFB 5 Year Periodic Maintenance Schedule for 4kV motors
   g. EFB #1 Stack Inspection Report March 2012
   h. EFB #2 Stack Inspection Report June 2014
   i. EFB #1 Boiler FM Global Summary
   j. EFB #2 Boiler FM Global Summary
   k. E.F. Barrett Power Station Hurricane Sandy Damage
   l. Barrett 1 High Energy Piping Condition Assessment
   m. Barrett 2 High Energy Piping Condition Assessment
   n. EFB 1 AMPS 2013 History Chart
   o. EFB 2 AMPS 2011 History Chart
3. **Northport Power Station Documentation**
   a. NPT Motor & Pump Status 9-5-14

b. Northport 1 High Energy Piping Condition Assessment 2013 Final
c. Northport 2 High Energy Piping Condition Assessment (post 2012-2013 outage)
d. Northport 3 High Energy Piping Condition Assessment 2013 Final with Priority
e. Northport 4 High Energy Piping Condition Assessment 2012-2014
f. NPT-Major Capital Improvements 8-21-14(2)
g. BLRHISTR rev. 19
h. Power Plant Operation Hurricane Sandy Damage
i. NPT Reserve Shutdown NERC GADS Entries 2011 to present
j. NPT NERC GADS Events 2011 thru July 2014
k. NPT Unit 1 Stack Inspection Report
l. NPT Unit 2 Stack Inspection Report
m. NPT Unit 3 Stack Inspection Report
n. NPT Unit 4 Stack Inspection Report
o. Summer Prep 2014
p. Summer Prep 2013
q. Summer Prep 2012 rev.1
r. Summer Prep 2011
s. Summer Prep 2010
t. Summer Prep 2009
u. NPT 1 Factory Mutual Boiler Inspection Report
v. NPT 2 Factory Mutual Boiler Inspection Report
w. NPT 3 Factory Mutual Boiler Inspection Report
x. NPT 4 Factory Mutual Boiler Inspection Report
y. NPT 1 AMPS 2014 History Chart
z. NPT 2 AMPS 2014 History Chart 3
aa. NPT 3 AMPS 2014 History Chart-1
bb. NPT 4 AMPS 2014 History Chart

4. **Port Jefferson Power Station Documentation**
    a. PJ 3 1999 Field Boresonic Inspection
    b. PJ 3 2007 LPDF Boresonic Inspection
    c. PJ 3 2007 IPLPSF Boresonic Inspection
    d. PJ 3 2007 HP Boresonic Inspection
    e. PJ 4 2010 HP IPLPSF LPDF Boresonic Inspection
    f. Port Jefferson Unit #3 Chimney Inspection Report 2014-2
    g. Port Jefferson Unit #4 Chimney Inspection Report Fall 2013
    h. PJ 3 2014 Condition Assessment Recommendation
    i. PJ Unit 3 High Energy Piping & BOP Condition Assessment Proposal Fall 2014
    j. PJ Unit 4 High Energy Piping Condition Assessment History 6-26-12
    k. PJ Outage Schedule 2009-2019
    l. Port Jeff Pump & Motor Data
    m. Port Jeff 4 kV Motor Inventory as of 4-30-12
    n. PPO-Major Improvements to Port Jeff units from 2004 to present
    o. PJ 3 FM Boiler Report
    p. PJ 4 FM Boiler Report
    q. Summer Prep LIPA 2014 rev.1
    r. Port Jeff Unit #3 Chimney Inspection Report 2013
    s. Port Jeff Unit #4 Chimney Inspection Report Fall 2013
    t. PJPS Unit 3 Unit 4 Boiler Tube Outages
    u. PSEG PJ Steam 2011-2013
    v. PJ 3 AMPS 2011 History Chart
    w. PJ 4 AMPS 2011 History Chart
5. **E.F. Barrett GT Site Documentation**
    a. CT 2015 to 2019 Generation Preliminary 5 yr Capital Budget LIPA PSA submittal 7-10-14
    b. PPO Major Capital Improvements Gas Turbines by unit 8-21-14
    c. 10b hot Section
    d. Final Shop Report 018860 Nat Grid FT4A P675476

e. Final Shop Report 018859 Nat Grid GG4A P675476

f. EFBGT 8 HPI Borescope 2008

6. Holtsville GT Site Documentation

a. Holtsville 686604 HSI

7. Port Jefferson GT Site Documentation

a. LM6000PC – 191422

b. LM6000PC – 191412

8. Wading River GT Site Specific

a. WR3 Borescope Report 03-12-13

9. PSA GT Fleet Summer Availability

10. PPA GT Fleet Summer Availability

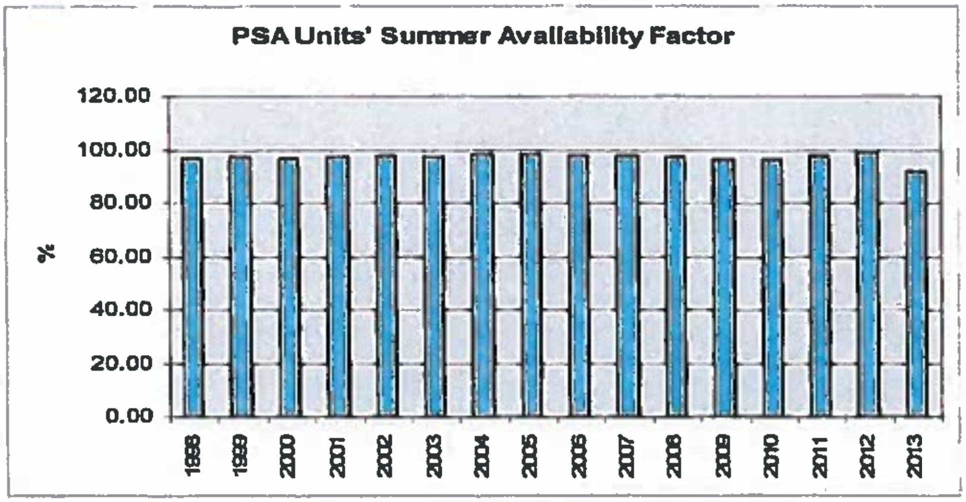
11. GT Starting Reliability

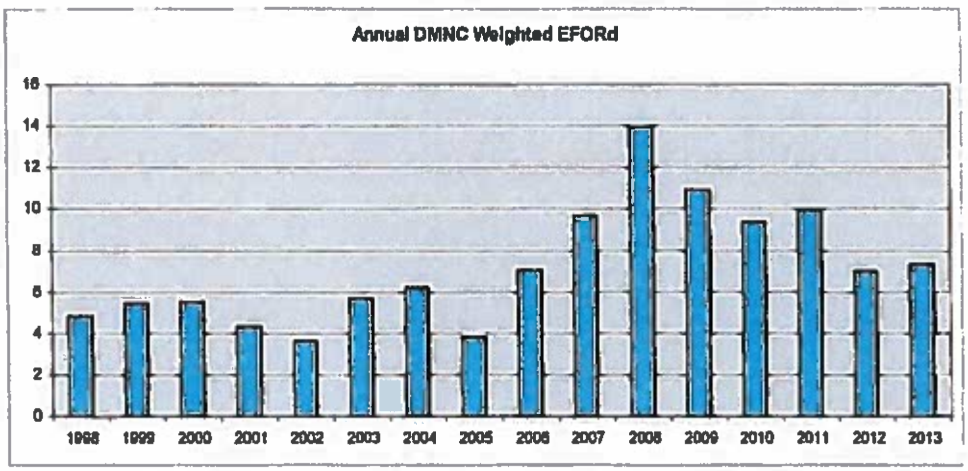
12. Technical Information Letter TIL 1576

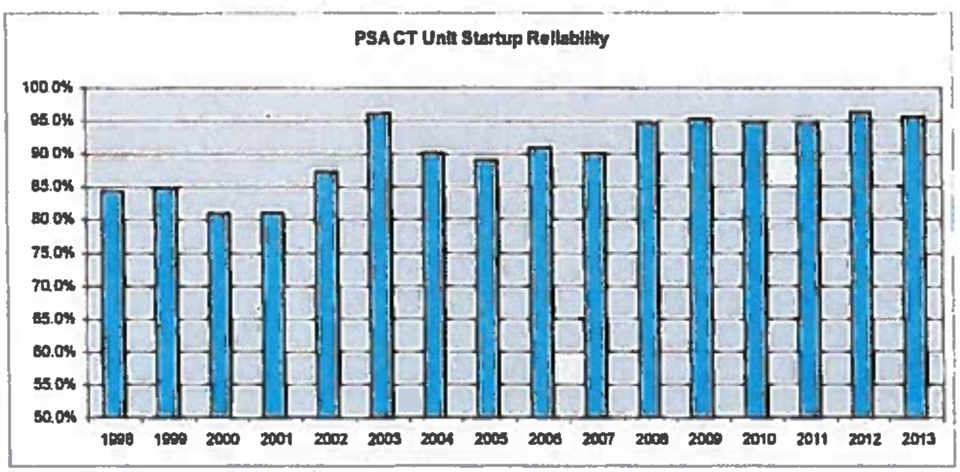
13. GE Frame GT Remaining Starts

APPENDIX 1.4

PSA Units Summer Availability Factor / Annual DMNC Weighted EFORd / PSA CT Unit Startup Reliability


PSA Units' Summer Availability Factor
120.00
100.00
80.00
60.00
40.00
20.00
0.00
%
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013


Annual DMNC Weighted EFORd
16
14
12
10
8
6
4
2
0
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013


PSA CT Unit Startup Reliability
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
65.0%
60.0%
55.0%
50.0%
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013

Appendix C: Northport Repowering Attributes Summary

Northport Repowering - Phase 1 & 3 Estimated Performance							
Configuration - 7F.05 1x1 CCGT							
Fuel		**Natural gas**			**Fuel Oil**		
Ambient Dry Bulb	def F	15	59	92	15	59	92
Relative Humidity	%	60	60	60	60	60	60
CTG Load	%	100%	100%	100%	100%	100%	100%
Evap Cooler Status	On/Off	Off	Off	On	Off	Off	On
CTG Gross Output	kW	257,154	241,015	228,064	262,989	259,026	244,872
STG Gross Output	kW	120,852	119,045	106,097	117,199	123,366	109,574
Plant Gross Output	kW	378,006	360,060	334,161	380,108	382,392	354,446
Plant Net Output	kW	368,570	350,513	324,815	371,995	373,835	346,042
Auxiliary Load	kW	9,436	9,547	9,346	8,113	8,557	8,404
Plant Net Heat Rate (HHV)	Btu/kWh	6541	6,560	6,833	7,010	6,960	7,247
Water Injection for NOx Control	kpph	0	0	0	142	142	137
Part Load Configuration - 7F.05 1x1 CCGT							
CTG Load	%	75%	75%	75%	75%	75%	75%
Evap Cooler Status	On/Off	Off	Off	Off	Off	Off	Off
CTG Gross Output	kW	181,926	172,445	162,443	185,130	187,552	174,928
STG Gross Output	kW	102,702	98,917	89,502	100,732	100,631	92,852
Plant Gross Output	kW	284,628	271,362	251,945	285,862	288,183	267,780
Plant Net Output	kW	276,417	262,867	243,592	278,500	280,346	260,031
Auxiliary Load	kW	8,211	8,495	8,353	7,362	7,837	7,749
Plant Net Heat Rate (HHV)	Btu/kWh	6,866	6,786	7,079	7,352	7,135	7,479
Water Injection for NOx Control	kpph	-	-		112	109	106

Min Load Configuration - 7F.05 1x1 CCGT							
CTG Load	%	41%	42%	42%	50%	50%	50%
Evap Cooler Status	On/Off	Off	Off	Off	Off	Off	Off
CTG Gross Output	kW	105,816	101,118	95,418	134,566	125,814	117,221
STG Gross Output	kW	82,065	75,779	69,453	88,541	82,342	76,563
Plant Gross Output	kW	187,881	176,897	164,871	223,107	208,156	193,784
Plant Net Output	kW	180,963	169,547	157,604	216,293	200,919	186,609
Auxiliary Load	kW	6,918	7,350	7,267	6,814	7,237	7,175
Plant Net Heat Rate (HHV)	Btu/kWh	6,795	6,655	6,992	6,979	6,801	7,189
Water Injection for NOx Control	kpph	7,522	7,367	7,740	7,726	7,529	7,958
EMISSIONS							
		Controlled at ISO			**Controlled at 15°F ambient**		
NOX	lb/MMBTU	0.00724			0.02377		
NH3	lb/MMBTU	0.00669			0.00732		
CO	lb/MMBTU	0.00442			0.00482		
PM (including Ammonium Sulfates)	lb/MMBTU	0.0066			0.01984		
SO2	lb/MMBTU	0.00136			0.00152		
CO2	lb/MMBTU	115.67			161.89		
NOX	ppm @ 15% O2	2			6		
NH3	ppm @ 15% O2	5			5		
CO	ppm @ 15% O2	2			2		

Northport Repowering – Phase 2 Estimated Performance							
Configuration - 7F.05 2x0- SCGT							
Fuel		**Natural gas**			**Fuel Oil**		
Ambient Dry Bulb	def F	15	59	92	15	59	92
Relative Humidity	%	60	60	60	60	60	60
CTG Load	%	100%	100%	100%	100%	100%	100%
Evap Cooler Status	On/Off	Off	Off	On	Off	Off	On
CTG Gross Output	kW	259,315	242,865	229,661	259,901	252,795	246,443
Plant Gross Output	kW	518,630	485,730	459,322	519,802	505,590	492,886
Plant Net Output	kW	508,693	476,159	450,022	512,399	498,266	485,630
Auxiliary Load	kW	9,937	9,571	9,300	7,403	7,324	7,256
Plant Net Heat Rate (HHV)	Btu/kWh	9,548	9,721	9,921	10,089	10,233	10,406
Water Injection for NOx Control	kpph	0	0	0	282	278	275
Part Load Configuration - 7F.05 2x0- SCGT							
CTG Load	%	75%	75%	75%	75%	75%	75%
Evap Cooler Status	On/Off	Off	Off	Off	Off	Off	Off
CTG Gross Output	kW	195,034	182,652	172,768	195,498	190,173	185,404
Plant Gross Output	kW	390,068	365,304	345,536	390,996	380,346	370,808
Plant Net Output	kW	381,521	357,118	337,522	384,300	373,711	364,225
Auxiliary Load	kW	8,547	8,186	8,014	6,696	6,635	6,583
Plant Net Heat Rate (HHV)	Btu/kWh	10,410	10,312	10,669	11,073	10,825	11,149

Water Injection for NOx Control	kpph	-	-	-	232	221	222
Min Load Configuration - 7F.05 2x0- SCGT							
CTG Load	%	41%	42%	42%	50%	50%	50%
Evap Cooler Status	On/Off	Off	Off	Off	Off	Off	Off
CTG Gross Output	kW	105,818	101,123	95,420	129,363	126,105	117,489
Plant Gross Output	kW	211,636	202,246	190,840	258,726	252,210	234,978
Plant Net Output	kW	205,039	195,910	184,569	252,758	246,279	229,142
Auxiliary Load	kW	6,597	6,336	6,271	5,968	5,931	5,836
Plant Net Heat Rate (HHV)	Btu/kWh	13,263	12,502	13,252	13,107	12,366	13,045
Water Injection for NOx Control	kpph	-	-	-	181	166	163

EMISSIONS			
		Controlled at ISO	**Controlled at 15°F ambient**
NOX	lb/MMBTU	0.00906	0.02378
NH3	lb/MMBTU	0.01339	0.01465
CO	lb/MMBTU	0.01102	0.01448
PM (including Ammonium Sulfates)	lb/MMBTU	0.0066	0.02035
SO2	lb/MMBTU	0.00136	0.00152
CO2	lb/MMBTU	115.67	161.89
NOX	ppm @ 15% O2	2.5	6
NH3	ppm @ 15% O2	10	10
CO	ppm @ 15% O2	5	6

Northport Repowering – Phase 3 SCGT Estimated Performance							
Configuration - 7F.05 1x0- SCGT							
Fuel		**Natural gas**			**Fuel Oil**		
Ambient Dry Bulb	def F	15	59	92	15	59	92
Relative Humidity	%	60	60	60	60	60	60
CTG Load	%	100%	100%	100%	100%	100%	100%
Evap Cooler Status	On/Off	Off	Off	On	Off	Off	On
CTG Gross Output	kW	259,315	242,865	229,661	259,901	252,795	246,443
Plant Net Output	kW	254,319	238,051	224,983	256,175	249,108	242,790
Plant Aux Load Output	kW	4,996	4,814	4,678	3,726	3,687	3,653
Plant Net Heat Rate (HHV)	Btu/kWh	9,549	9,722	9,922	10,090	10,234	10,407
Water Injection for NOx Control	kpph	-	-	-	141	139	138
Part Load Configuration - 7F.05 1x0- SCGT							
CTG Load	%	75%	75%	75%	75%	75%	75%
Evap Cooler Status	On/Off	Off	Off	Off	Off	Off	Off
CTG Gross Output	kW	195,041	182,658	172,775	195,504	190,179	185,411
Plant Net Output	kW	190,740	178,537	168,739	192,132	186,836	182,094
Plant Aux Load Output	kW	4,301	4,121	4,036	3,372	3,343	3,317
Plant Net Heat Rate (HHV)	Btu/kWh	10,411	10,314	10,670	11,074	10,826	11,150
Water Injection for NOx Control	kpph	-	-	-	116	110	111
Min Load Configuration - 7F.05 1x0- SCGT							
CTG Load	%	41%	42%	42%	50%	50%	50%
Evap Cooler Status	On/Off	Off	Off	Off	Off	Off	Off

CTG Gross Output	kW	105,818	101,123	95,420	129,363	126,078	117,489
Plant Net Output	kW	102,492	97,927	92,256	126,354	123,087	114,546
Plant Aux Load Output	kW	3,326	3,196	3,164	3,009	2,991	2,943
Plant Net Heat Rate (HHV)	Btu/kWh	13,266	12,507	13,256	13,109	12,369	13,048
Water Injection for NOx Control	kpph	-	-	-	91	83	81
EMISSIONS							
		Controlled at ISO			**Controlled at 15°F ambient**		
NOX	lb/MMBTU	0.00906			0.02378		
NH3	lb/MMBTU	0.01339			0.01465		
CO	lb/MMBTU	0.01102			0.01448		
PM (including Ammonium Sulfates)	lb/MMBTU	0.0066			0.02035		
SO2	lb/MMBTU	0.00136			0.00152		
CO2	lb/MMBTU	115.67			161.89		
NOX	ppm @ 15% O2	2.5			6		
NH3	ppm @ 15% O2	10			10		
CO	ppm @ 15% O2	5			6		

Northport Repowering - All Phases BESS Estimated Performance		
Configuration - 50 MW x 4 hrs BESS		
Attribute/ Assumption	**Measure**	**Comments**
BESS Rated Output (MW)	50	Levelized by annual augmentation
Total Hours in Year	8,760	Equals 365 x 24
Planned & Maintenance Outages	(300)	Average Expectation
Total Hour, Net of Outages	8,460	Net Hours
Estimated Availability	95%	Typical Contract Requirement
Annual hours available	8,037	Factors in Availability
Annual days per year available	335	Days Available
Discharge Duration in hours	4	BESS Design Criteria
Annual Generation Hours	1,340	Assumes 1 cycle per day
Annual Generation in Mwhrs	67,000	Rated Output x Generation Hrs
Round Trip Efficiency	85%	Assumed Performance
Charging Power in Mwhrs	78,824	Annual Charging Power

LAST PAGE OF APPENDIX C

Appendix D: Northport Repowering Project Schedule (Scenario 3)

Repowering Feasibility Study

	NORTHPORT STATION REPOWERING- DRAFT 4/3/19 REV	YEAR 1 (2021)	YEAR 2 (2022)	YEAR 3 (2023)	YEAR 4 (2024)	YEAR 5 (2025)	YEAR 6 (2026)	YEAR 7 (2027)	YEAR 8 (2028)	YEAR 9 (2029)	YEAR 10 (2030)	YEAR 11 (2031)	YEAR 12 (2032)	YEAR 13 (2033)	YEAR 14 (2034)	YEAR 15 (2035)
PHASE 1	PHASE 1A- ARTICLE X (COMBINED CYCLE CC1 ON NORTH LAWN)	ART X CC1														
	PHASE 1A- DEMO FO 2 & 3 TANKS (CURRENTLY OUT OF SERVICE)			FO 2 & 3												
	PHASE 1A- DISTILLATE TANK FARM ON FO 2 & 3 AREA			DIST. TANKS												
	PHASE 1A- COMBINED CYCLE CC1 - (F CLASS) - 340 MW			COMBINED CYCLE 1												
	PHASE 1A-SHUTDOWN STEAM UNIT U1					⊗										
	PHASE 1A-PARTIAL U1 DEMO - BOILER & STACK															
	PHASE 1B- ARTICLE X (BATTERY 1 ON TANK 5 DIKE EXCESS AREA)	ART X BATT 1														
	PHASE 1B- RECONFIGURE TANK 5 DIKE AREA			DIKE												
	PHASE 1B- BATTERY 1 - 50 MW				BATTERY 1											
PHASE 2	PHASE 2A- ARTICLE X (SC 1 & 2 ON SITE SOUTH OF UNIT 4)		ART X SC 1 & 2													
	PHASE 2A- SIMPLE CYCLE (SC 1 & 2) 460 MW				SIMPLE CYCLE 1 & 2											
	PHASE 2A- UNIT 2 SHUTDOWN							⊗								
	PHASE 2A- DEMO: U1 TURBINE BLDG & U2 & SERVICE BLDG							UNITS 1 & 2 DEMO								
	PHASE 2B- ART X (BATTERY 2 - ADJ TO WASTE WATER)		ART X BATT ERY 2													
	PHASE 2B- BATTERY 2 (50 MW)				BATTERY 2											
PHASE 3	PHASE 3A- ARTICLE X (CC2 ON U1 & U2 and SC3 SOUTH OF SC 1&2)							ART X CC2 & SC3								
	PHASE 3A- CC2 (340 MW) and SC 3 (230 MW)									COMB CYCLE 2 AND SIMPLE CYCLE 3						
	PHASE 3A- SHUTDOWN STEAM UNITS U3 & U4												⊗			
	PHASE 3A - DEMO STEAM UNITS U3 & U4												UNITS 3 & 4 DEMO			
	PHASE 3A - DEMO FO TANKS 1,4 & 5 AND WASTEWATER												DEMO FO			
	PHASE 3B- ARTICLE X BATTERY 3 ON FO TANK AREA											ART X BATT 3				
	PHASE 3B - BATTERY 3 (50 MW)													BATTERY 3		

SYMBOL NAME
CONSTRUCTION & STARTUP COMPLETE
⊗ EXISTING UNIT SHUTDOWN
NOTE THAT ARTICLE X PROCEEDINGS MAY BE CONSOLIDATED WITHIN EACH PHASE

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10	YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15
SITE MW CAPACITY (ISO) AVAILABLE BY YEAR:	1500	1500	1500	1550	1600	1565	1650	1650	1650	1650	1650	1470	1470	1520	
SITE MW WITH STEAM UNIT LOAD LIMITS				1500	1500	1500	1500	1500	1500	1500	1500				

TECHNOLOGIES: COMBINED CYCLE CC1 (F CLASS)=340 MW, COMBINED CYCLE CC2 (F CLASS)= 340 MW, SIMPLE CYCLE SC 1&2 (F CLASS)= 460 MW, SIMPLE CYCLE SC3 (F CLASS) =230 MW
BATTERY 1 = 50 MW, BATTERY 2 = 50 MW, BATTERY 3 = 50 MW
EXISTING STEAM UNITS U1 - U4 ARE NOMINAL 375 MW EACH FOR 1500 MW TOTAL
GUIDELINES: PHASE A - USE A COMBINATION OF ADVANCED F CLASS COMBUSTION TURBINES BOTH SIMPLE AND COMBINED CYCLE FOR LOAD FOLLOWING
PHASE B - PAIR EACH COMBUSTION TURBINE PROJECT WITH A LONG DURATION BATTERY ENERGY STORAGE PROJECT
MAINTAIN SITE MW CAPACITY AND MINIMIZE MW SHORTFALLS DURING PHASING
OPTIMIZE CONSTRUCTABILITY BY IDENTIFYING SITE SPACE LIMITATIONS

LIPA Long Island Power Authority

Appendix E: Production Cost Methodology

PRODUCTION COST METHODOLOGY

The need to reasonably accurately forecast total system production costs is critical in evaluating the potential benefits (or costs) associated with any proposed generating asset addition to LIPA's portfolio. A variety of industry-standard tools and models were used to evaluate Northport. Specifically, those tools include *Multi-Area Production Simulation (MAPS),* a production cost simulation program developed by General Electric (GE) for utility planners. MAPS integrates highly detailed representations of a system's load, generation, and transmission into a single simulation. This enables MAPS to calculate hourly production costs while recognizing the constraints imposed by the transmission system on the economic dispatch of generation. MAPS accurately simulates the operation of an interconnected power system in accordance with the least cost system dispatch, while respecting transmission limits and constraints. The program model can represent individual utilities and pools or combinations of both. All computations are performed while maintaining the chronology of the load model. Consequently, the MAPS model accounts for the load diversity present in the actual power system.

The MAPS model used consists of a representation of the 4-Pool system composed of New York, New England, PJM Classic (New Jersey and parts of Pennsylvania), and parts of Canada (Hydro Quebec and parts of Ontario)). The model contains system load, generation, and transmission data for all utilities in the 4-Pool system.

In terms of load forecasting, a 20-year forecast is submitted by LIPA for review and approval to the New York Independent System Operator (NYISO), which subsequently publishes the approved forecast in the "Gold Book". The forecast provides both annual peaks and energy requirements. For the rest of the areas in the 4-Pool model, the load is obtained from publications such as the Gold Book, PJM load report and ISO-NE's Capacity, Energy, Loads and Transmission (CELT) report. To perform hourly unit commitment and dispatch, hourly load profiles are obtained from the Load Forecasting group (for Long Island) and GE (for the rest of the model).

The generation system data in MAPS includes generator unit characteristics, such as multi-step cost curves, variable O&M costs, unit cycling capabilities, emission rates, outage rates and market bids by unit loading block. The generation units, along with chronological hourly load profiles, are assigned to individual buses on the transmission system. The generation database is updated on an annual basis to reflect unit retirements, installations, and changes in existing generation. For units on Long Island that are under contract to LIPA, detailed and proprietary updates are internally provided. For the rest of the generation in the 4-Pool system, the data is obtained from publications, such as Gold Book and other publicly available sources.

The transmission system is modeled in terms of individual transmission lines, interfaces (which are groupings of lines), phase-angle regulators (PARs), HVDC lines and various transmission system contingencies. The transmission model, known as load flow, is updated on an annual basis in coordination with NYISO. An annual system study – the Summer Operating Study - is performed to identify limitations on the transmission system and the impact of any system changes. Inputs regarding transmission configurations and limitations and assumptions regarding dispatch of supply resources are also incorporated into the load flow. A load flow analysis is then run that identifies locally constrained areas or areas that are at risk of being constrained in the near future. To reflect real system condition, these constraints are modeled in MAPS. In addition, LIPA's contracts, such as Transmission Congestion Contracts (TCCs), and generation contracts are also individually modeled in MAPS. The result is a model that mimics the operation of LIPA's system and provides an insight into the future generation profile.

MAPS commitment and dispatch process starts by creating a unit priority list. The priority list identifies the thermal generators that are available to serve the load during a particular hour. The order of the units within this list is based upon full load unit cost accounting for minimum down-time and minimum run-time constraints. Thermal generators that have been designated as "must-run" units have their minimum capacity committed first. The remainder of these units and the full capacity of all other units are then committed based upon economic order. This process continues until the sum of the continuous ratings of the committed units is greater than or equal to the load, and the sum of the maximum ratings of the committed units is greater than or equal to the load plus the required spinning reserve. Energy storage (ES) generators (such as pumped storage hydro or batteries) are committed next. Using the hourly commitment schedule and data provided from the load model, MAPS determines thermal unit cost curves to use in scheduling the ES units. The ES units are used to shave the peak loads. The ES units are operated until either the recharge costs exceed the incremental savings that result from peak shaving or storage limits are reached. Once the program has determined the energy storage schedule, the thermal unit commitment schedule is redeveloped using modified loads to reflect the ES recharging and generation. MAPS re-dispatches the thermal units on an hourly basis to meet the modified loads. Using the forced outage rates that have been defined for each of the thermal units and a random number generator, units are taken offline for random intervals for the year. This process is then repeated for the next study hour and continues until the conclusion of the Study Period.

For project evaluations, such as analyzing the impact of addition/retirement of generation, a reference model (case) is developed based on latest MAPS model and study assumptions. The reference case reflects the expected system conditions without the new project. A separate case with the project modeled is then developed from the reference case. Both cases are evaluated over a specific time frame, usually 20 years. Next, the two cases are compared to analyze the impact of the project on the system, such as changes to the other generation units on Long Island and purchases from the outside utilities; changes to the Long Island emissions; and/or financial production cost/savings. The production cost/savings are incorporated in a financial model that also uses other data, such as transmission costs, fixed costs, and capacity payments.

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Appendix F: Market Forecasting Methodology

MARKET FORECASTING METHODOLOGY

A capacity model is used to assist in both the planning and management of LIPA's resource needs and market requirements. The model, known as "Market Manager" is a Microsoft Excel based program which can perform both deterministic and probabilistic analyses when used in conjunction with @Risk, a Monte Carlo based statistics add-on for Excel produced by the Palisades Corporation. The following is a brief overview of the model, the different functions it performs and the outputs it provides for use in the areas of capacity resource planning and market management.

Load and Capacity Planning – Both load and supply data are entered into the model. The model uses the peak load forecast data approved by the New York Independent System Operator ("NYISO") for use in the identification and planning of long and short-term resource needs. This forecast is published annually by NYISO in its Load & Capacity Data "Gold Book" and is generally a 20-year forecast for NYISO Zone "K" (Long Island). [NYISO also publishes load forecast data for New York City, Lower Hudson Valley and the NYCA, which is contained here and used for price determinations by the model]. Long Island uses two peak load forecasts, a NYCA coincident peak – used to calculate the Installed Reserve Requirement ("IRM") and a Zone "K" non-coincident peak – used to calculate the Long Island Locational Requirement ("LI LCR"). The Zone "K" forecast is broken down by individual load components and programs (Demand Side Management, Retail Access, Feed in Tariffs, Municipalities, etc.) and then totaled to determine both Long Island and LIPA load and resource requirements. The IRM and LI LCR are determined by the New York State Reliability Council (NYSRC) and the NYISO, respectively, for the next calendar year. The IRM and LI LCR are forecasted beyond that by the service provider for the term of the load forecast. The model uses rating data for all Long Island based resources, including those under contract to LIPA as well as municipalities and merchant resources located in NYISO Zone "K". Individual data inputs include seasonal DMNC data, COD & retirement dates, contract start & end dates, NYISO PTID and other unit characteristic information. The load and resource data is used by the model to determine annual capacity resource positions and requirements for Long Island and LIPA.

Capacity Price Forecasting – Market Manager is also used to forecast capacity market prices for both short term (monthly) and long term (annually) planning purposes. NYISO uses the Monthly "Spot" Capacity Prices (also known as the Demand Curve Prices) as the market indices or proxy prices for capacity in New York. There are four locality prices in New York - NYCA, Lower Hudson Valley, Long Island and New York City. These prices are calculated in the model. The model includes all generating resources located in New York State and combines them with annual NYISO Demand Curve parameters to generate a Monthly Demand Curve price forecasts for each of the four localities. The price forecast model also uses historical prices to identify trends which are used to help determine future prices in each of these areas.

Market Purchases, Budgeting and Cost Estimation – The model is also used to estimate the cost of additional capacity resources purchased in the NYISO markets that are required by LIPA to meet its Installed Reserve Margin and Long Island Locality Requirements on a monthly and annual basis. The model uses load and resource forecasts for NYCA and Long Island and allocates to LIPA a pro-rata share of the overall supply in the NYCA and Long Island Markets. Resources under contract to LIPA each month are netted from the final resource allocations with the remaining resource allocations priced at the values determined in the capacity pricing model. Changes in assumptions such as load, supply, market transactions and pricing parameters all impact the results in this area. The final result is an annual market purchase cost associated with these additional capacity purchases that is calculated on a monthly basis for both the NYCA and LI capacity markets and summarized annually.

Probabilistic Modeling – Market Manager operates in a default deterministic mode. The model also has the ability to operate in a stochastic mode which replaces all individual input variables with user defined probabilistic inputs sampled by a Monte Carlo simulation. The model operates in conjunction with @Risk software to generate and store all input and output data when the probabilistic mode of operation is selected. Distributions for load and supply variables can include normal, discrete, triangle, and a host of others including customized functions and dependent variables. Selected outputs that are displayed include load requirements, supply positions, resource needs, market costs, market price forecasts as well as many others. Probabilistic outputs are displayed in chart form (Confidence Intervals) as well as in graph form.

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