DRAFT

Repowering Feasibility Study
Port Jefferson Power Station

Draft as of April 19, 2017

CONTENTS

CONTENTS

CONTENTS

TABLES AND FIGURES

EXECUTIVE SUMMARY

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 the Authority), in cooperation with its service provider (PSEG Long Island) and the owner of the legacy LILCO power generating stations (National Grid or Grid[1]), to perform, or direct the performance of, engineering, environmental permitting and cost feasibility analyses and studies (Study or Studies) 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 to be completed and presented to the LIPA Board of Trustees (Board) and the Long Island branch of the New York Department of Public Service (NYDPS) no later than April 2017. The Northport repowering Study is to be completed no later than April 2020. Upon completion of the Studies, the Authority, if it were to find, in accordance with the Studies' findings, 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)[2] related to repowering.

As required by the Bill, this Study evaluates repowering the Port Jefferson facility using more efficient and environmentally friendly technologies. It is not a broad assessment of all system-wide options available to the Authority, some of which are likely to produce environmental and efficiency effects similar to or perhaps greater than those achieved by repowering Port Jefferson, and possibly at lower cost. For example, in lieu of repowering Port Jefferson, an alternate investment to build a new renewable energy facility, or a new simple or combined cycle facility at a different location, or retiring Port Jefferson and upgrading the proximate transmission system infrastructure (thereby eliminating all local power plant emissions), may be more cost effective and environmentally friendly than repowering Port Jefferson. Or, a Port Jefferson repowering of a different size and technology (e.g., simple cycle as opposed to combined cycle) might provide similar environmental benefits while proving better suited to the future needs of customers. Accordingly, it is important to note that there are other potential options available to the Authority that might achieve the same or greater benefits, at a lower cost, as a Port Jefferson repowering. A full analysis of these options, however, falls outside the scope of this Study.

1 Throughout this Study, "Grid" is used to identify any of the following entities/terms: National Grid USA, National Grid Generation, National Grid, and GENCO. Grid owns the legacy LILCO power generating stations.

2 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.

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

This report represents the results of the Port Jefferson repowering Study and is presented in conformance with the requirements of the Bill. The following summarizes the conclusions of the Study:

- A repowering of the Port Jefferson power station is feasible from a technical and environmental permitting perspective but is not economic (i.e., does not pay for itself), and does not offer more reliability benefits than other system alternatives.
- The total aggregate cost to LIPA's customers is $840 million from 2019 - 2030 and $1.115 billion through 2035, the end of the study period.[3]
- The total additional cost for an average residential customer is $373 through 2030 and $485 through 2035.[4]
- The decline in natural gas prices since 2008 makes repowering more uneconomic.
- The existing Port Jefferson steam units have operated at a five-year average capacity factor of 11%[5]. This compares to a high of 48% in the late 1990's. Seasonal variations include higher summer-month operations (capacity factors are approximately 40%) and peak winter-month operation when ambient temperatures are cold. During spring and fall months, capacity factors are very low. The utilization of the steam units may continue to decline as LIPA invests in renewable generation required to meet New York State's 50x30 Clean Energy Standard (CES).
- An independent plant condition assessment indicated that the existing Port Jefferson 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[6]. The condition

[3] Cost impacts are measured against the Integrated Resource Plan Reference case.
[4] Ibid
[5] A capacity factor of 100% means that a plant would be operating at its full capacity every hour of the year.
[6] "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 31, 2014.

assessment results are consistent with recent operating performance. For example, during the period 2010-2015 the steam units' annual Equivalent Forced Outage Rate-demand[7] (EFORd), one of the North American Electric Reliability Corporation's (NERC's) best indicators of operational reliability, averaged 2.1%. Overall, Port Jefferson's performance compares favorably to similar units in operation during this time frame, as discussed in Section 2 of this Study.

- A repowering of the steam units would provide environmental and efficiency benefits relative to the existing Port Jefferson steam units; however, LIPA normally evaluates investments at multiple locations or other configurations before committing to such significant costs to determine if competing proposals would provide greater benefit to LIPA's customers.

- The current size of LIPA's generation portfolio is greater than current needs and is projected to remain so for the foreseeable future. This excess provides LIPA 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.

- Significant uncertainty exists around the size, timing, type, and location of new renewable generation to be built on Long Island pursuant to the CES. 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 2017 peak-load forecast for 2030 is approximately 1,700 megawatts (MW) less than the forecast for 2030 prepared in 2013, resulting in a peak load forecast reduction or over four times the size of the proposed Port Jefferson combined-cycle unit. At present, LIPA is forecasted to have surplus generation capacity until 2035. These factors and the continuation of such trends could render alternative generation configurations at the Port Jefferson site or other sites more attractive to LIPA's customers.

- The Study assumes property taxes associated with the repowered unit would remain at the same level as the existing plant, which are over twice the level paid on a per megawatt basis for other combined cycle plants installed on Long Island.

- LIPA has certain rights acquired at the time of the LILCO merger to lease or purchase parcels at the Port Jefferson site for the purpose of constructing new generation. If a decision were made to build

[7] The lower the EFORd, the better the performance.

units at the Port Jefferson site in the future, rather than sole source a contract with the incumbent owner, LIPA would evaluate exercising its rights and use competitive procurement processes among multiple developers to obtain the lowest cost for its customers.

The Existing Plant

The Port Jefferson power plant site is located on Beach Street in the town of Brookhaven and the Village of Port Jefferson along the north shore of Long Island in Suffolk County, NY. The parcel of property is approximately 73 acres. In total, the plant site consists of five operating and two decommissioned units. The five operating units at Port Jefferson are grouped into two separate power facilities, one operated under the PSA, the other under a Purchase Power Agreement (PPA) with LIPA.

The PSA units consist of three (3) of the operating units:

- Two steam units (Units 3 and 4, commissioned in 1958 and 1960, respectively) with an approximate 380-MW total capability;
- A 12-MW (summer rating) GE Frame 5 gas turbine commissioned in 1966.

In addition to the PSA units, there are two 40 MW GE LM6000 gas turbine units, known as the Port Jefferson Energy Center, that are operated by Grid as a separate power generation facility in accordance with a PPA with LIPA. Those units are not included in the scope of this Study. Port Jefferson Units 1 and 2 were removed from service in 1994 and decommissioned in place. Notwithstanding the ages of Port Jefferson Units 3 and 4, the results of an independent plant condition assessment conducted in late 2014 (confirmed to remain valid as part of this Study) indicate that the units are well maintained, reliable for their age and can, with reasonable projected capital, operations and maintenance expenditures can maintain that reliability for the foreseeable future. Expenditures on the existing units have been assumed in evaluating the benefits of repowering with new units.

In 1996, the capability to burn natural gas was added to Units 3 and 4, giving them the ability to burn either natural gas or fuel oil. The No. 6 fuel oil burned at Port Jefferson is a 0.5% sulfur residual fuel oil. For the two steam units, there are no unit-specific NOx emission rate limits, however, there is a NOX Reasonably Available Control Technology (RACT) regulatory target of 0.15 lbs/MMBtu regardless of fuel. Natural gas is delivered by a pipeline extension of the Local Distribution Company (LDC). There is a gas flow limitation to the station during periods of high demand, such as summer months. During those situations, a combination of natural gas and No. 6 fuel oil is burned based on economic dispatch by the NYISO. The steam units are once-through cooled with sea water from the plant's intake structure and discharge to Port Jefferson Harbor. The electrical point of interconnection is to an onsite LIPA substation.

The Proposed Plant

A "repowered" generating facility is often defined as "reusing" certain major mechanical equipment, such as the steam turbine, from the existing facility. In the case of Port Jefferson, however, Grid studied a repowering configuration that would replace the two steam units (each unit consisting of a single boiler and steam turbine) with a Siemens SGT6-8000H combustion turbine (CT) generator in a 1x1x1 configuration (one CT generator exhausting into one heat recovery steam generator (HRSG) that drives one steam turbine (ST) generator). The SGT6-8000H was selected as representative of the highly-efficient H-class machines that are available in today's market. The 1x1x1 combined-cycle configuration has a nominal net summer rating of 400 MW, a specified design criteria for the repowered unit. The 400 MWs essentially replaces in kind the existing two steam units' capacity.

The proposed repowered plant offers fuel and environmental benefits over the existing facility. Environmentally, the repowered unit lowers emissions of greenhouse gases (CO_2) by about 35%, lowers nitrous oxides (NOx) emission rates by about 90%, and would displace emissions from other plants. Of note, the proposed plant would have greater total emissions than the existing facility because of its expected higher capacity factor – i.e., its <u>rate</u> 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 <u>total</u> 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 Port Jefferson site, though, would be offset by reduced total 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 Port Jefferson.

As noted, the new units would be more energy efficient, having lower fuel or variable costs ($/MWh) than that of the existing units. Notwithstanding these fuel savings, the repowered units would increase overall costs to LIPA ratepayers as the <u>total</u> cost of the proposed units, which includes its fixed costs to construct the new units, is calculated to be greater than the cost of maintaining and operating the existing facility. An apt analogue is that of replacing an old, moderately driven and well maintained car with a newer, more fuel efficient model. The newer model would get much better gas mileage (i.e., lower variable cost), but the older model would be, in total, less costly to the owner (i.e., LIPA's customers) as it avoids the high new car payment.

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, however, the only factors. In addition, particularly in New York, consideration must be given to the 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 Port Jefferson, or any other plant on the system. For example, the CES requirement to obtain 50% of the State's energy from renewable resources by 2030 (i.e., "50 x 30") requires the construction of significant amounts of new renewable generation. Additionally, the State's announced goal to develop 2,400 MWs of offshore wind would require operational changes to LIPA's generation, transmission and distributions system assuming, reasonably, that some portion of such development will be offshore Long Island and connect to the LIPA system. The potential level of generation intermittency accompanying such an offshore wind buildout would require types, amounts, and location of generation, batteries, demand response, or other resources that are yet unknown but are likely to be different from the current system configuration. It is, therefore, difficult at this point to ascertain whether a repowered unit at Port Jefferson of the type proposed would provide the necessary and optimal support to a system that may be very different from the current system.

Another important consideration in a decision regarding Port Jefferson is the dramatically declining load-growth projections for Long Island. As recently as 2013, the peak-load forecast for 2030 was projected to be 7,040 MW, while the most recent peak-load projection for 2030 is 5,341 MW—a reduction of 1,699 MW, or over four times the size of the proposed repowering project. The forecasted peak-load reductions result in a projected surplus of generation capacity until 2035.

Cost of the Proposed Plant

Grid developed two pricing proposals for the repowering option, the proposals representing 30-year and 40-year PPAs. The 40-year PPA option was considered too long and inconsistent with both the Authority's generation planning horizon and fiscal policies that limit borrowing or financing facilities to 30 years. Importantly, the 40-year option would provide lower initial cost but significantly higher total cost. Grid's pricing included the option of either fixed monthly capacity payments along with variable operations and maintenance charges or lower initial capacity payments that would escalate annually. Provision of fuel would be the responsibility of the

Authority. Because repowering Port Jefferson requires the existing steam units be retired and demolished prior to the start of construction of the repowering project, certain transmission reinforcements are required to account for the absence of Port Jefferson's capacity during the period between retirement of the existing units and commercial operation of the new unit.

The evaluation of the Port Jefferson repowering proposal was based on a model that is used for LIPA's financial projections. A key model assumption was that the repowered unit's annual taxes would be the same as that incurred on the existing unit. Those taxes are over twice what LIPA would likely pay for new generation of similar size in other parts of Long Island.

Conclusion

The Authority has determined that a repowering of the Port Jefferson power station is feasible from a technical and environmental permitting perspective. A repowering would provide environmental and efficiency benefits relative to the existing plant, but it is presently not economic nor required for system reliability purposes. If the Port Jefferson power station were to be repowered, rates to customers would increase above where they would be otherwise. Further, given the uncertainty around the timing, size, type and location of new generation to be built on Long Island pursuant to the Clean Energy Standard, declining energy usage due to energy efficiency and distributed resources, and the relatively sound operating condition and reliability of the existing generating facilities at Port Jefferson (and the rest of the PSA units), major decisions on fleet modernization are best deferred until there is greater clarity and more in-depth study on the key factors that contribute to the current high level of uncertainty, including evaluation of generation investments at other locations that may provide equal or greater environmental and operating benefits to LIPA's customers at a lower cost. Accordingly, the proposed repowering is not in the best interests of LIPA's customers.

LAST PAGE OF EXECUTIVE SUMMARY.

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, in cooperation with its service provider and the owner of the legacy LILCO power generating stations (i.e., National Grid or Grid), to perform an engineering, environmental permitting and cost feasibility analysis and study (the Study) of repowering of Port Jefferson. Further, the Bill required LIPA to study repowering utilizing greater efficiency and environmentally friendly technologies and be completed and presented to the Board of the Long Island Power Authority and the New York State Department of Public Service (NYSDPS) by April 2017.

1.1 SCOPE & OBJECTIVE

The scope of this Study is to perform an engineering, environmental, permitting, and cost feasibility analysis of the potential repowering of Port Jefferson. While it does include system-wide energy and capacity impacts that result from such a repowering and does make assumptions regarding important local issues such as property taxes, the report's scope does not include the impacts of exogenous factors, such as compliance with the State's 50 x 30 CES beyond an initial 400 MWs of renewable generation investment.

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

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

1.2 APPROACH

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

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

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

- Define the repowering scenario to be considered and why that scenario was selected.
- Provide the background and information required to assess the repowering scenario.
- Based on the inputs developed for the Study, assess repowering engineering characteristics and issues, such as:
    - What facility changes would result from repowering?
    - Based on these changes, 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.

- Issues associated with severe storms.

- 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.
    - Impact on the community.
    - Financial cost to LIPA customers.

In addition to the analyses, assessments and considerations above, the Study also considered the changing environment in which the decision to repower Port Jefferson would be made. These issues, such as ongoing New York State energy programs and efficiency initiatives, advances in renewable energy technologies (such as offshore wind), 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.

LAST PAGE OF SECTION 1.

2. BACKGROUND & INPUTS

The Study uses existing applicable and relevant information, including that from Grid's recent repowering feasibility study.[8] This information consists of the current plant configuration and capabilities, repowering options and corresponding key attributes, and assumptions required to analyze relevant engineering, economic, and environmental factors.

2.1 CURRENT PLANT DESCRIPTION

Port Jefferson is located on Beach Street in the town of Brookhaven and the Village of Port Jefferson along the north shore of Long Island in Suffolk County, NY. The parcel of property is approximately 73 acres. The plant consists of five operating and two decommissioned units. The five operating units at Port Jefferson are grouped into two separate power facilities, one operated under the PSA, the other under a Purchase Power Agreement (PPA) with LIPA.

The PSA units consist of three (3) of the operating units:

- Two steam units (Units 3 and 4, commissioned in 1958 and 1960, respectively) with an approximate 380-MW total capability
- A 12-MW (summer rating) GE Frame 5 gas turbine commissioned in 1966.

In addition to the PSA units, there are two 40 MW GE LM6000 gas turbine units, known as the Port Jefferson Energy Center, that are operated by Grid as a separate power generation facility in accordance with a PPA with LIPA. Those units are not included in the scope of this Study. Port Jefferson Units 1 and 2 were removed from service in 1994 and decommissioned in place.

In 1996, the capability to burn natural gas was added to Units 3 and 4, giving them the ability to burn either natural gas or fuel oil. The No. 6 fuel oil burned at Port Jefferson is a 0.5% sulfur residual fuel oil. For the two steam units, there are no unit-specific NOx emission rate limits, however, there is a NOx RACT regulatory target of 0.15 lbs/MMBtu regardless of fuel. Natural gas is delivered by a pipeline extension of the Local Distribution Company (LDC). There is a gas flow limitation to the station during periods of high demand, such as summer months. During those situations, a combination of natural gas and No. 6 fuel oil is burned based on economic dispatch by the NYISO. Natural gas, the primary fuel consumed by the steam units, is delivered by a

[8] "Repowering Feasibility Study of Port Jefferson Power Station," National Grid, February 27, 2017

pipeline extension of the Local Distribution Company (LDC). There is a gas flow limitation to the station that limits the gas-fired generating capability of the steam plant and the neighboring Port Jefferson Energy Center. When maximum generation is needed, either the steam units or the gas turbines are switched to fuel oil. The steam units are once-through cooled with seawater from the plant's intake structure and discharged to Port Jefferson Harbor. The electrical point of interconnection is an on-site LIPA substation.

2.2 CURRENT PLANT OPERATIONS

The station is economically dispatched by the NYISO. Each unit normally operates from a minimum load of 40 MW to a design load of 181 MW[9]. The guaranteed ramp rate in the normal operating range is 2 MW per minute. The station provides ancillary services in the form of voltage support services (including testing for leading and lagging VARs), frequency regulation, and 10-minute synchronous reserve response.

The existing Units 3 and 4 follow a seasonal operational trend. The five-year average capacity factor, 2012 – 2016, is 11%. Seasonal variations include higher summer-month operation (capacity factors are approximately 40%) and peak winter-month operation when ambient temperatures are cold. During spring and fall months, capacity factors are very low. The full-load heat rate for Units 3 and 4 are approximately 10,500 Btu/kWh when burning natural gas.

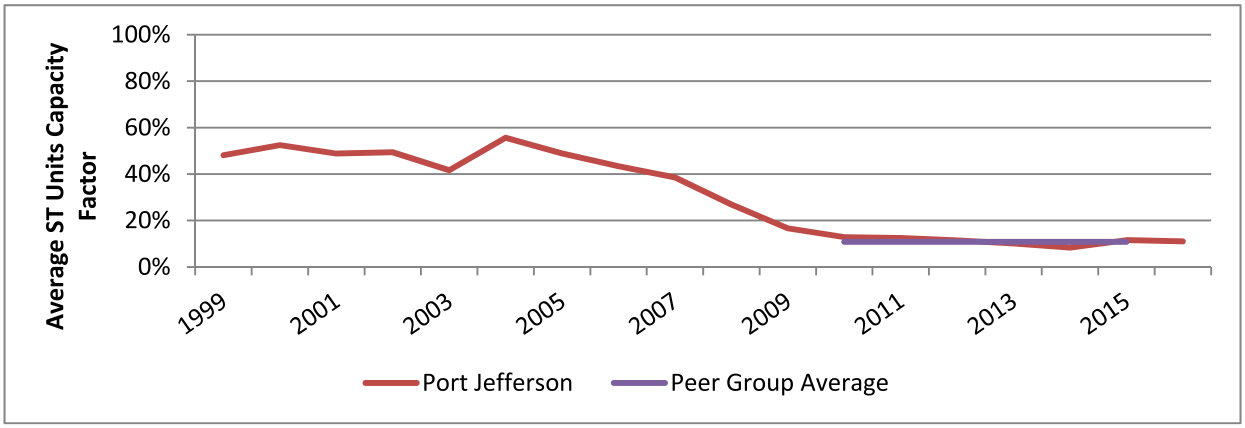
To further assess the performance of the Port Jefferson units, they were compared to 53 comparable steam units operated by 28 other utilities during the period 2010 through 2015. Details of the benchmarking comparison are provided in Appendix A.[10] Of the key performance statistics, relevant comparisons 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 EFORd indicates how much a unit cannot run when it is called to run, which is often considered the best indicator of a unit's reliability. The average CF of the peer group was 10.8%, the average summer EAF was 88% (higher is better), and the average EFORd was 10.6% (lower is better).

[9] Nameplate capacity.

[10] Note that the 29 utilities and 57 units shown in Appendix A include National Grid and the four (4) Barrett and Port Jefferson steam units.

Figure 2-1 provides the historical net CF for the Port Jefferson units, as well as the average of their peer group during the period 2010-2015[11].

Figure 2-1 — Steam Units Historical Capacity factors

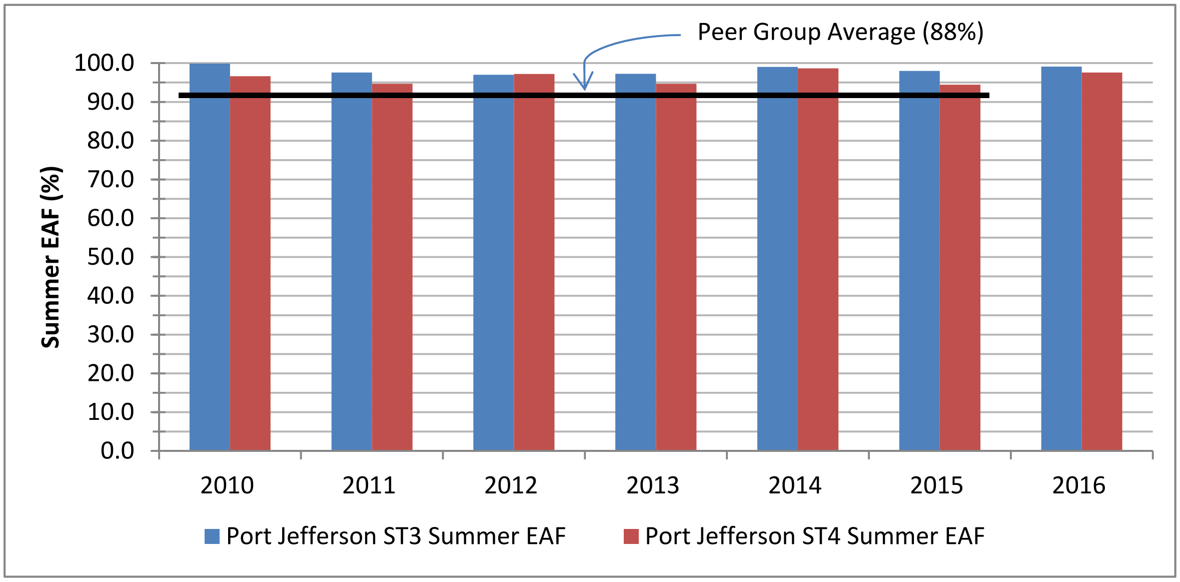


Port Jefferson's capacity factor declined from the late 1990's, from a high of 54% in 2004 to 11% in 2016; the station's average capacity factor for the last five years was approximately 10%.

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 Port Jefferson's EAF during these summer months.

[11] Peer group data for 2016 is not available.

Figure 2-2 — Summer Equivalent Availability Factor



Port Jefferson's EAF performance from 2010 – 2015 for the months of June, July and August was excellent, averaging over 97% (compared to 88% for the peer group), and reflects the results of Grid's operating philosophy. These EAF values also are consistent with Port Jefferson's annual average EFORd performance for the same period, a low 2.1%, which compares favorably to the peer group mean of 10.6% and supports the independent condition assessment prepared by RCMT.

Port Jefferson Units 3 and 4 operate in compliance with all permits. There are multiple permits issued by the NY State Department of Environmental Conservation, primarily covering air emissions, water use and discharge, and storage of liquid fuel. The air permit sets limit based on pollutant and fuel type. The 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 emission rate limit for these units, there is a regulatory target of 0.15 lbs/MMBtu regardless of fuel. On gas, these units typically operate 40-50% below the regulatory target. When combusting No. 6 fuel oil, the units normally emit at 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 discharges are reported to the USEPA and/or 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 Port Jefferson Harbor. 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.

2.3 CONDITION OF EXISTING FACILITIES

RCM Technologies, Inc. (RCMT), performed a high-level condition assessment in 2014 of Grid's power generation units under contract to LIPA through the PSA, which includes the Port Jefferson units. (See Appendix B for a redacted version of RCMT's report.) Overall, the condition assessment determined that the units can reliably operate at least until expiration of the PSA in 2028. This conclusion is 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 program. Accordingly, the Study assumed continuing capital expenditures through 2030 totaling approximately $60 million.

During this Study 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 Port Jefferson units compare favorably to similar units in operation, further supporting the conclusions of the RCMT Assessment. Accordingly, the conclusions reached in the 2014 RCMT condition assessment are considered to remain valid, and Port Jefferson can reasonably be expected to operate reliably at least through the termination of its PSA contract.

LAST PAGE OF SECTION 2.

3. REPOWERING CONFIGURATION

The repowering configuration selected for this Study includes an advanced Siemens SGT6-8000H combustion turbine generator (CTG) in a 1x1x1 configuration (i.e., one (1) CTG exhausting to one (1) heat recovery steam generator exhausting to one (1) steam turbine generator). The SGT6-8000H was selected as representative of the highly-efficient "state-of-the-art" H-class machines that are available in today's market. This 1x1x1 combined-cycle configuration has a nominal net summer rating of 400 MW, a specified design criteria for the repowered unit. The 400 MW essentially replaces in kind the existing two steam units' capacity, which would be decommissioned and razed to make room for the new unit.

The new unit would utilize natural gas as its primary fuel, with provision for ultra-low-sulfur distillate (ULSD) fuel as a backup. For emissions control, the CTG would include advanced dry low-NO_X combustors when operating on natural gas and water injection when operating on ULSD. The triple-pressure reheat heat recovery steam generator (HRSG) would include an integral selective catalytic reduction (SCR) system, carbon monoxide (CO) catalyst, and incorporate appropriate emission controls required for air permit compliance. To improve efficiency, the CTG inlet would be equipped with evaporative cooling. The unit would be designed for rapid startup with 100% steam bypass to an air-cooled condenser (ACC) and be capable of low-load operation in compliance with permitted emissions to provide flexibility in daily operation. An auxiliary boiler would assist rapid starts by providing start-up steam for HRSG warming, turbine seals, and condenser air removal.

Since the unit would be cooled by an ACC, this would eliminate the current once-through cooling system. Water would be supplied to the new unit by means of the existing Suffolk County Water Authority line, with demineralized water for HRSG makeup supplied by means of portable demineralizer units. Demineralized water storage would be in a new, field-erected 750,000-gallon tank located near the fuel oil tank area, along with unloading and pumping facilities for the demineralized water treatment system. An existing 100,000-gallon condensate storage tank would be reused to store makeup water to the ACC's hotwell.

A detailed attributes matrix is shown in the following tables that provides conceptual-level performance data for both fuel types (natural gas and ULSD) and at various load conditions. Gross and net performance data for three temperatures (92°F, 59°F, and 25°F) for natural gas and one temperature (25°F) for distillate fuel (ULSD) is included. The performance tables also include a summary showing emission rates for NO_X, SO_2, CO, carbon dioxide (CO_2), and particulate matter (PM).

Table 3-1 — Port Jefferson Repowering Attributes Summary

PERFORMANCE -GAS FIRING

Ambient Temperature: 25F		25	25	25
Load Points: 100% /75%/Min		100	75	45
Heat Input - Mbtu/hr (HHV)		2,956	2,316	1,649
Gross heat Rate- Btu/kWh (HHV)		6,406	6,585	7,134
Gross Power Output -MW		461.4	351.7	231.1
Aux Power- MW		15.0	11.9	9.1
Net Power -MW		446.4	339.8	222.0
Net Heat Rate- Btu/kWh (LHV)		5,970	6,146	6,697
Net Heat Rate - Btu/kWh (HHV)		6,621	6,816	7,427
Fuel Flow Rate (kscf./hr)		2,904	2,276	1,620

Ambient Temperature: 59F		59	59	59
Load Points: 100% /75%/Min		100	75	45
Heat Input - Mbtu/hr (HHV)		2,792	2,203	1,569
Gross heat Rate- Btu/kWh (HHV)		6,323	6,494	7,064
Gross Power Output -MW		441.5	339.2	222.1
Aux Power- MW		15.3	12.3	9.3
Net Power -MW		426.2	326.9	212.8
Net Heat Rate- Btu/kWh (LHV)		5,906	6,076	6,650
Net Heat Rate - Btu/kWh (HHV)		6,550	6,738	7,375
Fuel Flow Rate (kscf./hr)		2,743	2,164	1,542

Ambient Temperature: 92F		92	92	92
Load Points: 100% /75%/Min		100	75	45
Heat Input - Mbtu/hr (HHV)		2,681	2,019	1,448
Gross heat Rate- Btu/kWh (HHV)		6,513	6,705	7.3
Gross Power Output -MW		411.7	301.2	198.9
Aux Power- MW		14.8	12.0	9.6
Net Power -MW		396.8	289.2	189,230
Net Heat Rate- Btu/kWh (LHV)		6,092	6,296	6,900
Net Heat Rate - Btu/kWh (HHV)		6,756	6,982	7,652
Fuel Flow Rate (kscf./hr)		2,634	1,984	1,423

EMISSIONS (Gas): lbs/Mbtu (HHV) - Controlled at ISO		lbs/MMBtu	ppm @ 15% O_2
NOx also ppm		0.00726	2
NH3 also ppm		0.00671	5
CO also ppm		0.00442	2
PM (including Ammonium Sulfates)		0.00444	
SO2		0.00056	
CO2		116.74	

Required GT Natural Gas inlet pressure per Siemens - psig 551 to 584

NG supply pressure (assumed) 150

PERFORMANCE -OIL FIRING

Ambient Temperatures: 25F		25	25	25
Load Points -100%/75%/Min		**100**	**75**	**60**
Heat Input - Mbtu/hr (HHV)		2,520	2,016	1,758
Gross Heat Rate- Btu/kWh		6,682	6,809	6,992
Gross Power Output -MW		377.1	296.1	251.4
Aux Power- MW		8.8	7.6	7.1
Net Power -MW		368.3	288.5	244.3
Net Heat Rate- Btu/kWh (LHV)		6,397	6,534	6,728
Net Heat Rate - Btu/kWh (HHV)		6,842	6,988	7,196

EMISSIONS: lbs/Mbtu (HHV) - Controlled at 25°F ambient		lbs/MMBtu	ppm @ 15% O_2
NOx also ppm		0.02341	6
NH3 also ppm		0.00721	5
CO also ppm		0.00475	2
PM (including Ammonium Sulfates)		0.02652	
SO2		0.00152	
CO2		159.92	

OPERATIONS

Startup Time to STG Bypass Valves Closed

Cold Start		160	mins
Warm Start		72	mins
Hot Start		42	mins

Ramp Rate from Min Load 30 MW/min (CTG ramp)
40 MW/min possible with STG lag

LAST PAGE OF SECTION 3.

4. ENGINEERING & ENVIRONMENTAL ANALYSIS

Based on the current background, inputs, and assumptions discussed in Section 2, this section of the Study assesses the engineering and environmental elements of the repowering project. For example, the repowering project will need to identify and obtain the necessary permits and licenses required to build and operate the repowered plant, as well as the required supporting studies.

4.1 ENGINEERING CONSIDERATIONS

4.1.1 Proposed Repowering Option

Table 4-1 provides a detailed summary of the existing units and major components at Port Jefferson, and how they will be dispositioned under repowering.

Table 4-1 — Disposition of Major Plant Components

Existing Units & Components	Description & Comments	Total Current Output	Disposition	Total Repowering Output
Units 1 & 2	Two 40-MW steam units of late 1940s vintage. Removed from service in 1994.	-0-	Remove	0
Units 3 & 4	Boiler and steam turbine units. Unit 3 commissioned in 1958 and Unit 4 in 1960. To be decommissioned and razed to make room for the new unit.	380 MW	Retire & Remove	0
GT1	GE Frame 5 gas turbine commissioned in 1966.	12 MW	Remain	12 MW
2 – CT Units	Two GE LM6000 combustion turbine units, 40-MW each. Commissioned in 2002.	80 MW	Remain	80 MW
1 – CC Unit	One 1x1x1 combined-cycle (CC) unit (1 unit = 1 CT, 1 HRSG, & 1 ST)	0	New	400 MW

Existing Units & Components	Description & Comments	Total Current Output	Disposition	Total Repowering Output
Balance-of-Plant Equipment	Various	n/a	Reuse or Retire	n/a
Admin. Building	Requires demolition and removal before installation of new 1x1x1 CC unit.	n/a	Demolish & Remove	n/a
	Plant Output, Current & Repowered	472 MW		492 MW

The combined-cycle unit would operate on natural gas and have ultra-low sulfur distillate (ULSD) fuel backup, with an on-site five-day storage capability. It would have advanced dry low-NO_X combustors for natural gas firing and water injection for NO_X control on distillate (ULSD) fuel. An SCR system and any other necessary emission controls would be included in the design.

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

Additional, specific design parameters include combustion turbine evaporative cooling, 100% steam bypass to the ACC on the combined-cycle unit, auxiliary fin-fan cooling, and key equipment redundancy to achieve high availability.

4.1.2 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 (e.g., the proposed combined-cycle unit) is provided in Section 3, Table 3-1, which is a detailed Repowering Performance Attributes Matrix that includes gross and net performance data for three (3) temperatures (92F, 59F and 25F) for natural gas, and one temperature (25F) for distillate fuel (ULSD). The Attribute Matrix also includes a summary showing emission rates (NOx, SO_2, CO, CO_2, and PM). These attributes have been used in the transmission, dispatch, and economic analytical models for this Study.

4.1.3 Fuel Supply, Delivery, and Storage

As noted in Section 2.1, natural gas is delivered by a pipeline extension of the local distribution company. There is currently a gas flow limitation to the station during periods of high demand, such as summer months. During those situations, a combination of natural gas and No. 6 fuel oil would be burned based on the NYISO's economic dispatch. The LM6000 gas turbine units burn natural gas as a primary fuel and kerosene as backup. Residual oil is supplied to the plant by barge at unloading facilities located along the plant's Port Jefferson Harbor waterfront and stored in three bulk storage tanks that are located on the property and on the crest of a hill with an elevation of approximately 100 feet. Kerosene delivery is by tanker truck.

Grid determined that for the repowered unit that two off-site pipeline reinforcements would be required in order to supply sufficient pressure and quantities of natural gas. Design, engineering, and construction would be performed by the LDC, and the projects would require licensing under Article VII of the Public Service Law as well as by the LDC. Associated costs were included in the proposed pricing provided by Grid.

4.1.4 Electric Interconnection

Electric power from the new unit would be stepped up to 138 kilovolts (kV) and routed using existing towers that interconnect at the on-site LIPA substation. The unit would also be capable of an on-site black start by using power back-fed from the site's GE Frame 5 black-start peaking unit (GT1).

4.2 TRANSMISSION SYSTEM

The proposed Port Jefferson repowering project assumes that the existing steam Units 3 and 4 (380 MW total) are retired, demolished, and replaced with a combined-cycle facility consisting of a new 1x1x1 H-frame Frame unit (i.e., a combustion turbine generator, a heat recovery steam generator, and steam turbine generator) with a nominal capacity rating of 400 MW. The goal of this analysis was to ensure that given construction of the project that the transmission system would continue to adhere to NERC's transmission planning standards, and to determine if, in adhering to those standards, there would be upgrades and associated expenditures required to accommodate the project.

Typically, if an existing plant were to be replaced by a new facility of essentially the same capacity, there would, under most conditions, be no transmission upgrade costs associated with the repowering. Unlike some power plant locations, site considerations at Port Jefferson dictate that the existing units must be retired and demolished prior to the construction of any new facility. That is, there would be a period of approximately four years between the retirement and demolition of the existing plant and the commercial operation of a new plant. Under those conditions, allowances need to be made to address conditions on the bulk power system. The discussion below addresses those considerations.

The following table presents the results of a recent screening analysis performed to identify the reinforcements needed to permit the shutdown of the existing steam plant while the repowered unit is constructed.

Table 4-2 — Results of the Latest Analysis

Conductor	Contingency	Line Loading (w/o Port Jeff. Steam units and all Holtsville GTs [69 & 138 kV] dispatched)	Cost ($ million) (includes 50% R&C)
Elwood – Pulaski	Port Jefferson Bus 2	105.1%	$15
Holbrook – West Bus 138 kV	Pilgrim 138/69 kV Bank #3	100.3%	$2
Subtotal for Thermal			**$17**
2 STATCOM or SVC plus devices with Substation Reconfiguration	TVR Support		$60
Total: Thermal & Voltage			**$77**

4.2.1 Conclusion

Site considerations at Port Jefferson require the retirement of the existing plant prior to the start of construction of the new facility. Under those conditions, retirement of the two Port Jefferson steam units will result in transmission system reinforcements to accommodate both thermal and voltage constraints. Those reinforcements are preliminarily estimated to cost approximately $77 million and could vary significantly based on a comprehensive system assessment.

Importantly, since 2016 all LIPA 138-kV facilities are required to adhere to NERC Transmission Planning (TPL) standards, which drive compliance with N-1-1 system conditions. This review did not include N-1-1 contingency assessments and cost estimates to address these contingencies. The resulting cost impacts can significantly vary based on further thermal assessments. Detailed system studies would need to be performed to assess the comprehensive system impact of the retirement of Port Jefferson steam Units 3 and 4 and is not considered in the scope of this screening analysis.

4.3 ENVIRONMENTAL CONSIDERATIONS

4.3.1 Project Licensing & Permitting

The project would be subject to licensing and permitting under both NYS Department of Public Service and Department of Environmental Conservation (DEC) regulations. The project would be considered a ‘major electric generating facility and subject to Article 10 of the New York State Public Service Law. The project would also require air and water permits issued by the DEC. The two proceedings would be held jointly.

Article 10 of the Public Service Law is specifically designed to simplify and expedite licensing of electric generating facilities of 25 Megawatts or greater. The regulations roll up virtually all State and Local licensing and permitting requirements into a single process under a Siting Board. The Article 10 process and application requirements are very prescriptive, calling for 41 separate topics – from land use and air emissions to impacts of electric systems and telecommunications – that would need to be covered in the Application.

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 would identify 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 that are 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 4.3.2). Once the Application is submitted and deemed complete the project would be evaluated based on the results of 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). As noted above the proceedings for both would be held jointly.

A successful proceeding would result 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 air, water, and waste permits by the NYSDEC.

4.3.2 Required Permits

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

Table 4-3 — 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) would 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.
State	NYSDEC	SPDES Permit Modification for Construction and Dewatering Activities	Required for construction that would 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.

Agency	Department	Permit/Approval	Agency Action
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 would 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 would 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
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 the Article 10 process.

4.3.3 Permitting Studies

The Article 10 Certificate process requires the preparation of numerous studies in order to assess any potential impacts resulting from a proposed project, including studies on air emissions and water. The Article 10 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 would also require air and water permits issued by the New York State Department of Environmental Conservation (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.

4.3.4 Repowering Plant Air Emissions and Water Issues

Port Jefferson currently complies with all existing emissions permits. The proposed repowered plant, though, offers fuel and emissions benefits relative to the existing facility. Environmentally, the repowered unit 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 Port

Jefferson site, though, would be offset by reduced total 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 Port Jefferson.

Regarding Section 316b of the Federal Clean Water Act, the existing Port Jefferson plant has received and complies with a NYSDEC State Pollutant Discharge Elimination System (SPDES) permit for the plant's circulating water system. This permit required installation of variable-speed drives (VSD) on circulating water pumps, a condenser vacuum priming system, and fish-friendly travelling screens, which have been installed. Repowering would utilize an air cooled condenser, thereby eliminating the existing once-through cooling system of Port Jefferson.

4.4 CONSTRUCTABILITY

It is anticipated that the project could be broken down into three distinct phases. Phase 1 would be project licensing. Once licensing is complete, Phase 2 would encompass decommissioning and demolishing the existing steam units. Demolition is estimated to take two years. During this second phase, it is expected that a Notice to Proceed (NTP) would be issued to commence engineering and initiate procurement of long-lead equipment. The objective would be to complete sufficient engineering to allow construction activities (Phase 3) to commence immediately upon completion of decommissioning and demolition of the site.

It will be imperative for the installation 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 is a likely approach, particularly regarding the HRSG and ACC. This approach will be beneficial to both reducing the amount of on-site labor activities as well as the number of large crane picks.

4.4.1 Demolition

Demolition will include decommissioning and demolition of Units 3 and 4, retired Units 1 and 2, and the administration building. The site is restricted to the east by the waterfront and a steep elevation change to the west, immediately adjacent to the existing units.

4.4.2 Equipment Delivery and Laydown

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 West Broadway (Route 25A) onto Beach Street along the west shore of Port Jefferson

Harbor. Beach Street is a narrow, two-way road with residences on one side and various marine and light industrial facilities along its shore side. This road has been used in the past to support delivery of minor equipment and material during the construction of the site's LM6000 units.

A second means of entry to the site is off Route 25A by means of a private road to the west, which provides access to the plant's waste treatment facility, the fuel oil tank farm, and the LIPA substation. This road continues past these upper-elevation facilities and winds down to the lower elevation of the main plant, entering the site from the south. In addition to offering a second route for delivery of material, equipment, and manpower, the road provides direct access to potential laydown and construction parking areas in the upper area of the plant, which is not otherwise available in the site's lower section of the property. Demolition of the existing tank farm area can also serve as a temporary area for laydown until the area is needed for the installation of the new field-erected oil tanks.

Larger equipment can also be received by way of barge delivery to a bulkhead area a short distance away to the south along Beach Street. This bulkhead offers the potential to support marine deliveries of large components for the repowering.

4.4.3 Impact of Existing Facilities on Construction Activities

The demolition of existing structures and construction of the new unit would need to take place directly adjacent to the existing LM6000 units. These units must be available to operate throughout the course of demolition and construction. It is likely that barriers would need to be constructed to isolate and protect the units. Certain construction activities would have to be scheduled during non-operating periods. Protecting the units and maintaining their ability to operate would be accounted for in the development of the design.

4.5 STORM PROTECTION

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, and so forth.

To harden the new unit from the potential damage resulting from exposure to a storm surge, plant equipment would be placed 2 feet above the 500-year stillwater flood elevation, identified as Plant Datum Elevation 17.5 (NAVD88 Elevation 13.8). Therefore, the minimum equipment base elevation would be elevated to Plant

Datum Elevation 19.5 (NAVD88 Elevation 15.8). This would be accomplished by the addition of fill where appropriate, by placing equipment on elevated pedestal foundations, or by extension of equipment structural steel supports. The design is based on Category III hurricane design standards. This compares to the elevation of the current plant of 15 feet.

LAST PAGE OF SECTION 4.

5. REPOWERING ECONOMIC VIABILITY

5.1 RAMP DOWN AND REPOWERING PROVISIONS

Under Article 10 of the PSA LIPA has the contractual right to reduce ("Ramp Down") the Port Jefferson generating unit capacity at the site, which it is obligated to purchase from Grid. The exercise of the Ramp Down is subject to the following conditions:

- Prior written notice: LIPA must provide a two-year notice for steam units and a one-year notice for all other PSA units.
- 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 units 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 O&M expenses (both allocated and direct) and 12 months of O&M expenses in the case of non-steam units, less
  - The "notional" tracking account up to the lesser of the Ramp Down payment or the amount in the tracking account.
- Retirement Eligible: The units to be ramped down are found to be able to be retired from a reliability perspective.

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 would be reduced accordingly. Grid, upon receipt of the Ramp Down notice must, within 90 days, advise LIPA whether Grid would either continue to operate the ramped down units or shut down and mothball or demolish the units. For purposes of this analysis, it was assumed that LIPA would exercise its rights under the Repowering Option (Article 11 of the PSA) and direct Grid to repower the Port Jefferson facility and that LIPA would enter into a mutually acceptable long term Purchase Power tolling agreement for the repowered units with Grid retaining ownership of the site.

Notably, 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 more detail in Section 5.3 of this study.

5.2 ECONOMIC ANALYSIS

5.2.1 Cost and Emission Impacts

The costs and benefits of a Port Jefferson Repowering are reflected in the results of the Production Costs and Financial Model runs.[12] 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.

5.2.2 Modeling Considerations

As noted, elements of the Financial Model include all costs expected to be incurred each year, including those associated with the following:

- Total fuel and purchased power costs (Production Cost Model)
- Electric transmission and distribution capital expenditures
- Payments LIPA makes for Power Purchase Agreements (PPA), including the PSA
- Operating Services Agreement (OSA)
- Property taxes (PILOTs)
- Debt service
- Satisfaction of LIPA coverage ratio targets
- LIPA's 18% ownership of Nine Mile Point 2

Production Costs and Financial Model runs were made for the Port Jefferson repowering based on Grid's 30-year term levelized price proposal,[13] which includes installation of one 1x1x1 H-class, gas–fired, combined-cycle unit (i.e., a total of ~400 MW). This proposal assumes that construction of the "new" (repowered) unit would occur on the Port Jefferson site after the shutdown and demolition of the existing Port Jefferson Units 3 and 4. Units 3 and 4 would be shut down in March 2019, and the commercial operation date (COD) of the repowered unit would be January 1, 2023.

Economically, Grid proposed that LIPA enter a long-term PPA for the repowered unit that contains the following major provisions, including certain pricing options:

[12] The key tools used to assess the production cost, emissions and capacity impacts are described in Appendix C - Production Cost Methodology, and Appendix D - Market Forecasting Methodology.
[13] 30-year term levelized price including gas upgrade costs.

- A 30-year or a 40-year term
- A constant (flat or levelized) annual capacity payment
- Fixed O&M payment escalated annually at Consumer Price Index (CPI)
- Variable operating costs, $/MWh charge escalating annually at CPI
- Property taxes (PILOTs) to be paid by LIPA
- LIPA would be responsible for fuel (gas) procurement, including delivery to the plant

Additionally, per the provisions of Articles 10 and 11 of the PSA, which provide for consideration of costs and credits associated with a Ramp Down of a PSA unit, LIPA would make certain one-time payments associated with the ramp down of the noted Port Jefferson units, such payments including the:

- Net book value of the ramped down units as of March 2019, less the applicable Appendix G (of the PSA) discount, less the amount in the notional tracking account,[14] and
- Costs associated with demolition and site remediation

LIPA payments under the PSA would be reduced to reflect the "removal" of the ramped-down Port Jefferson units. The reduction in the payments under the PSA would include costs associated with return and depreciation, direct and indirect O&M, and property taxes.

5.2.3 Results

The impact on LIPA annual revenue requirements associated with the Port Jefferson repowering proposal described above was measured as the difference between two Financial Model runs covering the 20-year Study period 2016 through 2035. The two runs are as follows:

- A "reference" case based upon the following: the currently approved load and energy forecast; the retention of the existing on-island power supply portfolio; the achievement of the LIPA Trustee's goal of 400 MW of renewable generation; the cables (Neptune and Cross Sound Cable) remaining in-service; and the satisfaction of local and statewide reliability obligations.[15]
- The "reference" case but for the assumed Port Jefferson repowering, as described above.

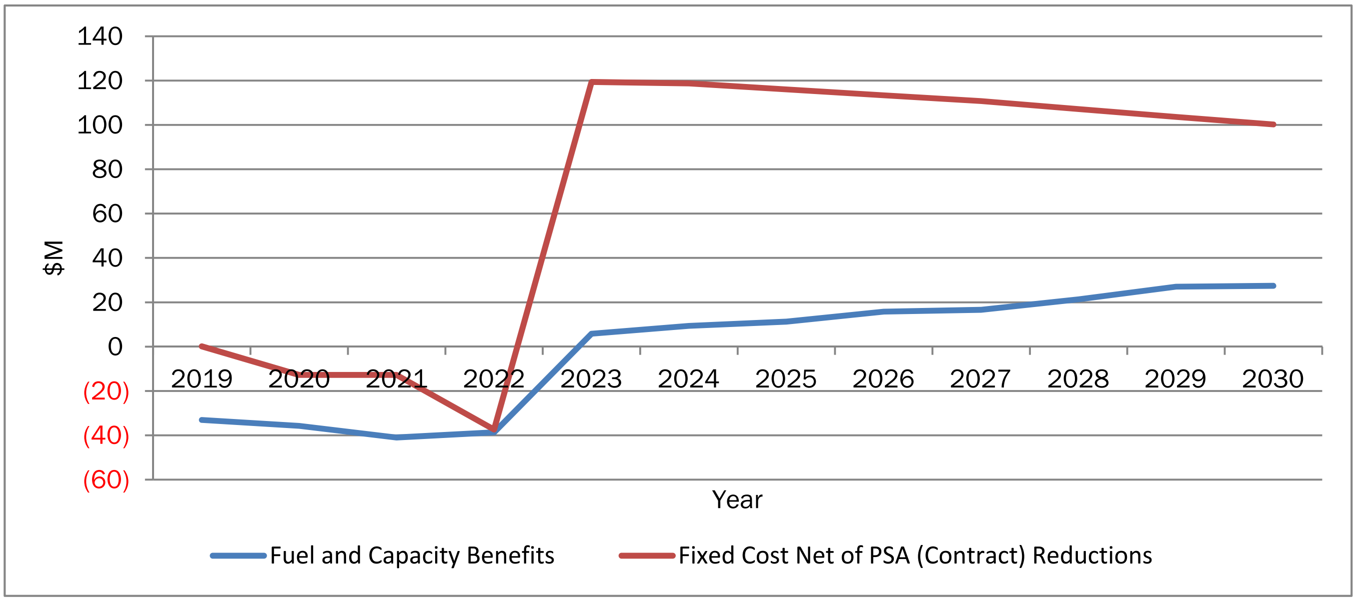
An important consideration affecting the financial modeling results was the decision to model only the effects of the 30-year term, flat-pricing option, as opposed to the 40-year flat-pricing option PPA. It is important to note

[14] The credit from the notional tracking account would be the lesser of the Ramp Down payment or the amount in the tracking account.
[15] Satisfying the LI Locational Capacity Requirement (LCR) and the statewide Installed Reserve Margin (IRM).)

that the Authority has never entered into a 40-year PPA and believes that such a contract duration is accompanied by significant risk, particularly in an environment with rapid and increasing technological advances and significant uncertainty regarding system needs so far in the future. In fact, the PSA and most PPAs that the Authority has entered have maximum terms of 20 years or less, not 30 years. A 40-year term is also beyond the tenor the Authority uses for its own borrowing and obligations.

Financial results are shown for the flat rate 30-year term pricing option for the period 2019–2030. Production cost modeling for the Integrated Resource Plan was the basis for the Port Jefferson repowering evaluation; the study period for that effort was the 20-year period 2016–2035.

Figure 5-1 — Increase in Annual Costs Associated with Port Jefferson Repowering

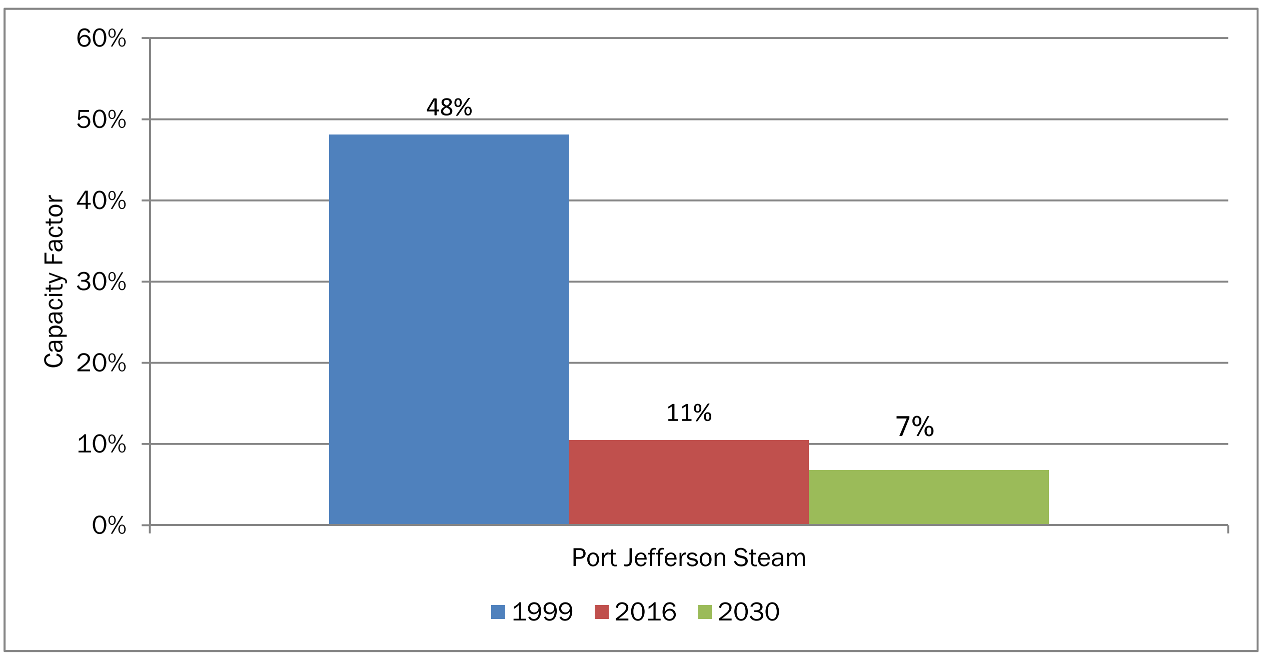


As shown in the results reflected in Figure 5-1, the Port Jefferson repowering proposal increases LIPA's cost in each year for the period depicted. In other words, the reduction in production costs (fuel and purchased power) attributable to the more thermally efficient repowered units, along with the decrease in the PSA annual "Capacity Charge" resulting from the retirement of the existing Port Jefferson units, is not sufficient to offset the higher PPA fixed costs associated with the repowered units.

As measured over the period 2019 – 2030, the total additional cost to LIPA's customers is $840 million and $1.115 billion over the course of the Study period (thru 2035). The total additional cost for an average residential customer is $373 thru 2030 and $485 through 2035.

In addition to cost impacts, the repowered project results in an approximate 3% decrease in LIPA's system-wide annual CO_2 emissions footprint, i.e., the reduction in emissions associated with satisfying LIPA's total annual energy requirements, assuming Port Jefferson is repowered as proposed. These emission reductions could potentially be achieved with alternative investments, providing greater operating and emission benefits. For example, a new combined cycle plant emits carbon dioxide at a rate of approximately 0.35 tons per MWh, while existing plants on average emit at a rate of approximately 0.6 tons per MWh. Thus, combined cycle plants save 0.25 tons per MWh of generation, while renewable energy saves the entire 0.6 tons per MWh. With respect to peaking options, old combustion turbines (such as those at Barrett and Holtsville) emit 0.9 tons per MWh, while new ones emit 0.6 tons per MWh – a savings of 0.3 tons per MWh. Thus, repowering combustion turbines reduces emissions at an even higher rate than repowering base load plants. In addition, Figure 5-2 shows the annual capacity factor of the Port Jefferson steam units for three distinct years.

Figure 5-2 — Port Jefferson Capacity Factor Trend



As shown, the annual capacity factor declined from 48% in 1999 to 11% in 2016 and is projected to decline to 7% by 2030. 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, even in the absence of repowering, emissions at Port Jefferson have declined significantly and will continue to decline over time due to changing system conditions brought on by, among other factors, energy efficiency programs and the introduction of increasing levels of renewable energy. Importantly, given the significant costs and the limited

benefits to LIPA's customers through 2035, a Port Jefferson repowering, could be contemplated later if the benefits are closer to costs. The opportunity to repower the plant or to evaluate other more cost effective alternatives does not diminish with time.

5.3 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 or its Agents, to build, own, and operate generating units on the acquired site. The following is a brief description of LIPA's rights under each option.

5.3.1 PSA Article 10 Capacity Ramp Down

In the event LIPA chooses to ramp down all or any portion of the generating facility capacity during the term of the PSA through 2028 and Grid notifies LIPA that it, pursuant to Section 10.2.2, would 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.[16] 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 with Grid to repower or construct new generation on the site. However, regarding the repowering of the steam units (e.g., Port Jefferson Units 3 and 4), 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.

Under Article 11, LIPA has the option during the terms of the PSA to direct Grid to ramp down and repower the generating facility, and Grid would be responsible for doing so. For each repowering that LIPA elects to exercise, LIPA and Grid would enter a separate PPA wherein Grid would be the owner/operator of the repowered facility and LIPA would be obligated to purchase the repowered generating facility's capacity, associated energy, and ancillary services.

5.3.2 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,

[16] 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.

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 would include the fair market value at the time of lease or purchase as determined by a jointly selected independent real estate appraiser.

LAST PAGE OF SECTION 5.

6. 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 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 Port Jefferson, or any other plant on the system. The type and nature of key changes, and their attendant uncertainties, are presented below.

6.1 STATE INITIATIVES

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

- **State Energy Plan (SEP):** Intended to coordinate all State agencies' efforts affecting energy policy to advance the REV agenda. It established NYS 2030 targets for greenhouse gas emissions, energy efficiency, and renewable generation (e.g., 50 x 30).
- **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 Blueprint for the Offshore Wind (OSW) Master Plan**: The Blueprint outlines the State's comprehensive offshore wind strategy and describes the benefits of developing the State's offshore wind potential. The Master Plan is anticipated to be released by year-end 2017
- **Clean Energy Standard (CES)**: A PSC Order adopting the SEP goal that 50% of New York's electricity is to be generated by renewable sources by 2030.
- **State Resource Plan (SRP)**: Intended to examine the effects of the various public policies on the State's bulk power system.

The details, costs, and implementation plans associated with state-level initiatives, particularly the CES and NYSERDA's Offshore Wind (OSW) efforts, will take a few years to fully unfold and their market and system implications to be fully understood. An assessment of the impact horizon associated with these initiatives is shown in Table 6-1 below.

Table 6-1 — Ongoing State Initiatives

State Initiative (Coordinated by SEP)	Timing*
Reforming the Energy Vision (REV)	Ongoing
State Resource Plan (SRP)	3 – 10 years
NYSERDA OSW Master Plan	5 – 14 years
Clean Energy Standard (CES)	1 – 14 years

* "Timing" is an estimate of the time frame during which the initiative could impact the size/configuration of LIPA's resource portfolio.

Note that except for REV, which represents various initiatives and approaches to the electricity markets, including distribution system automation, market restructuring, and increased consumer participation in markets, the impacts of the other initiatives are expected to occur over an extended time horizon. So, while there is uncertainty accompanying the nature and timing of the impacts of the initiatives, there is also time to develop appropriate plans and strategies to deal with those impacts.

For example, the State recently proposed a commitment to develop up to 2,400 MW of offshore wind power by 2030, thereby creating a focus on OSW development off Long Island. The State's vision will bring major operational changes to LIPA's transmission and distributions system assuming, reasonably, that a portion of such development will connect to the LIPA system. The types, amounts, and location of new generation, storage, demand response, or other distributed technologies that may be required are yet unknown but are likely to be different from the current system configuration. It is, therefore, difficult to ascertain whether a repowered unit at Port Jefferson of the type proposed will provide the optimal support to a system that may need to look very different than the current system. As events unfold, though, the basis for such a decision will become more evident.

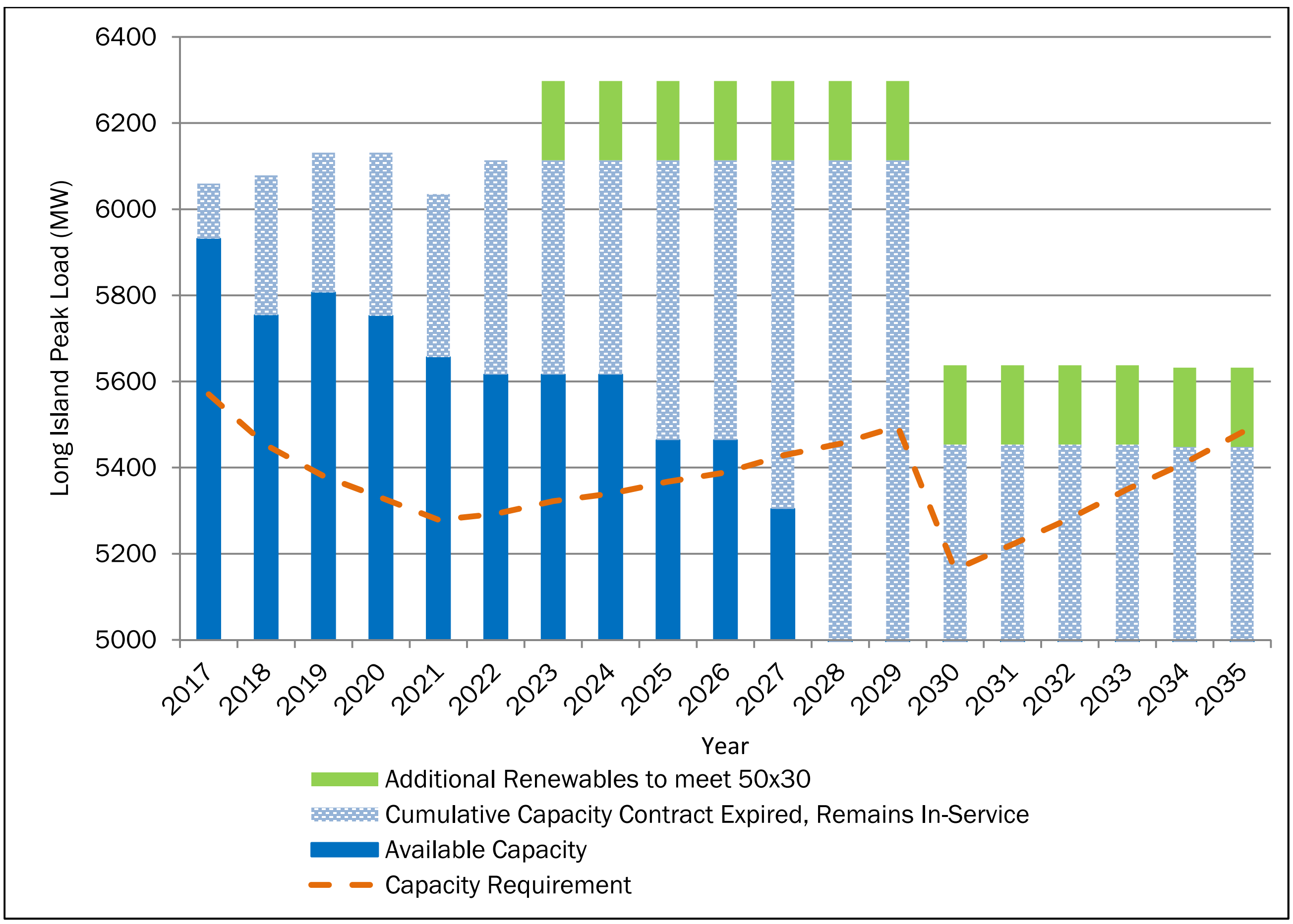
6.2 LIPA COMMITMENTS

Efforts to meet the Clean Energy Standard are being pursued via several resource procurements. Currently, the Authority is reviewing responses to two Feed-in-Tariff (FIT) solicitations, one for commercial solar photovoltaics (i.e., FIT III) and a second for fuel cell resources (i.e., FIT IV). In addition, responses to the 2015 Renewables RFP, which include OSW resources and on-island solar farms, are being examined. Furthermore, the Authority has recently executed a contract for a 90-MW OSW farm. The exact amount of renewable resources to be acquired, however, may be affected by the CES and NYSERDA's Offshore Wind Master Plan, still under development, and other factors.

6.3 PSA ASSETS, PPA CONTRACTS, & NEED FOR FLEXIBILITY

Due to the uncertainty over the next several years, there is a significant benefit to LIPA to keep as many options open as possible to enable selecting the best options for meeting its obligations at the lowest cost for its customers. Figure 6-1 illustrates the flexibility LIPA has to defer making significant capital decisions until there is more certainty in policy and regulatory requirements as well to take advantage of ongoing technology and industry development. Notably, LIPA has sufficient capacity for reliability purposes until 2035.

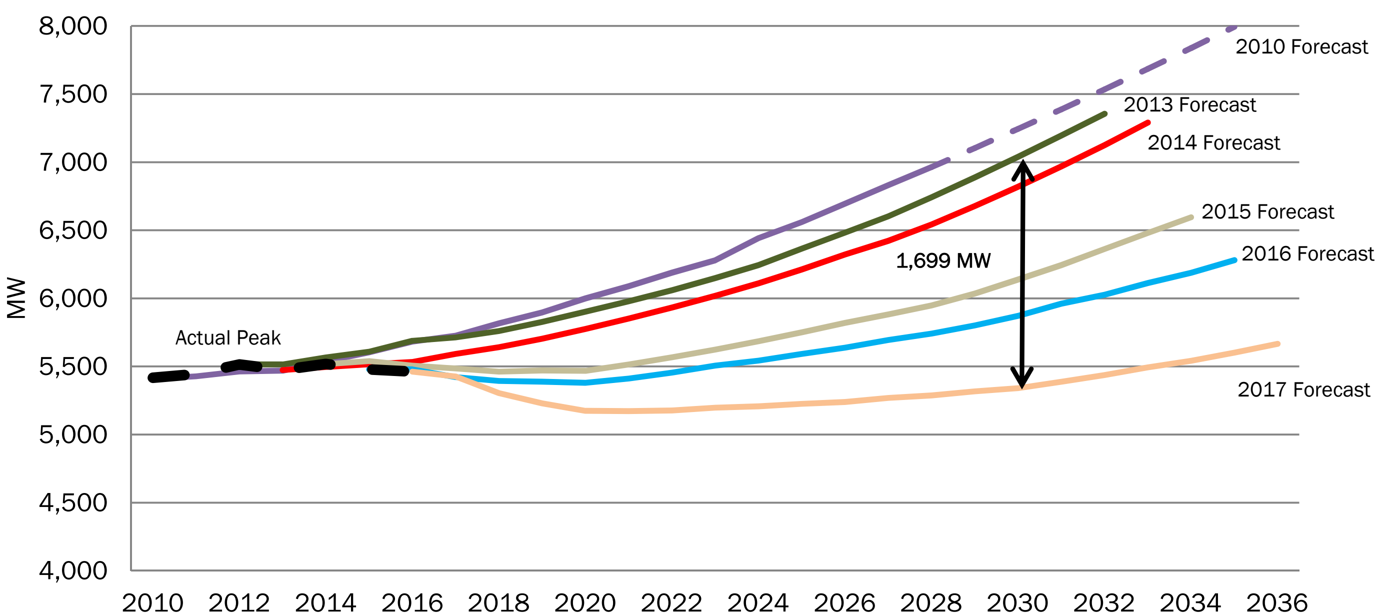
Figure 6-1 — Existing Capacity Resources and Contract Expiration



6.4 PEAK LOAD FORECASTS

The first and foremost goal of the Authority is to maintain system reliability. Doing so efficiently, economically, and in an environmentally sensitive manner is also important. 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 6-2 below, LIPA's peak load forecasts reveal dramatic year-on-year declines over the past five years.

Figure 6-2 — LIPA Peak Load Forecasts



These declines (reductions), driven by increasing penetration and effectiveness of energy efficiency, lower growth in econometric forecasts, and load modifier programs, have resulted in dramatic reductions in peak load and energy forecasts. For example, the peak load forecast for 2030 has been reduced by 1,699 MWs when comparing the 2013 forecast to the 2017 forecast, approximately four times the size of the proposed new unit. The result of these changes is that based on reliability considerations alone, and assuming LIPA's current generation portfolio remains in place, the Authority has surplus capacity until 2035. Consequently, system reliability considerations do not drive a need for a repowered Port Jefferson.

LAST PAGE OF SECTION 6.

7. IMPACT ON THE COMMUNITY

7.1 JOBS

Construction of the repowered unit would likely create nearly 400 jobs during peak construction months. The overall duration of the construct period is expected to range between two-and-a-half to three years, with the peak period occurring during the second and third quarter of the second year. Demolition of the existing facilities may take from one to two years prior to the start of construction of the new units but is expected to require less effort than construction of the new facility.

The staffing level for the repowered station would be less than current staffing. Port Jefferson currently requires approximately 60 on-site personnel. After repowering, the station would require approximately 25 - 30 personnel. Overall, the most significant impact on jobs is expected during the relatively short construction period. 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 is the level of taxes, PILOTS and fees (collectively referred to as Taxes in this Study) that the communities hosting the legacy power plants (i.e., those plants owned by Grid and under contract to supply power to LIPA) currently levy against these plants. The Authority's "Property Tax Reduction Efforts - 2017 Annual Report" identified the significant, disproportionate, and burdensome effect of Taxes on LIPA customers. Notably, Taxes, in all their forms, represent approximately 15 percent of a customer's monthly bill, or 3 times the national average. Total LIPA tax payments in 2016 totaled over $535 million, with $189 million of that total associated with property taxes on Grid-owned facilities covered under the PSA. Those facilities include the Barrett, Glenwood, Port Jefferson, and Northport plants.

Table 7-1 below illustrates the disproportionate property taxes levied in 2016 on the four legacy operating power plants, i.e., Port Jefferson, Barrett, Northport and Glenwood, compared to a non-legacy plant, represented by the Bowline Plant in Rockland County, NY. (Note that Glenwood's 200 MWs of steam units were decommissioned and demolished in 2013.)

Table 7-1 — Grid-Owned Plants' Disproportionate Legacy Property Taxes in 2016

Plant Name	Property Taxes	Summer Capability (MW)	Property Taxes ($/MW)
Glenwood (legacy)	$ 17,000,000	114	$ 148,395
Port Jefferson (legacy)	$ 28,000,000	393	$ 70,356
Barrett (legacy)	$ 36,000,000	663	$ 53,818
Northport (legacy)	$ 76,600,000	1,589	$ 48,200
Bowline	$ 2,700,000	1,135	$ 2,375

The disparity in both total taxes and tax on a $/MW basis between Bowline and Port Jefferson, and other legacy plants, is stark and informative. Grid did not provide a property tax estimate for the proposed repowered Port Jefferson unit so for analysis purposes the tax level for the repowered unit was assumed to be equivalent to the current tax level of approximately $28 million per year, which is over twice the level paid on a per megawatt basis for other combined cycle plants on Long Island. And taxes are disproportionately burdensome depending on location. This is not to imply that no taxes should be paid by customers to locales hosting power plants, rather only that the tax burden should be both equitable and reasonable. The Authority, as noted in its report, continues to strive to achieve that balance among its many properties for the benefit of its customers. The ongoing discussions between LIPA and the legacy tax jurisdictions further reinforces the benefits of using the flexibility and redundancy in the Authority's current generation portfolio to delay making a repowering decision when there is no obvious driver for doing so.

LAST PAGE OF SECTION 7.

8. CONCLUSIONS

This Study evaluated the engineering and environmental feasibility, and the economic viability, of repowering the Port Jefferson power plant. The repowering project is based on replacing the two existing steam units with a combined-cycle unit consisting of a Siemens SGT6-8000H combustion turbine generator in a 1x1x1 configuration (i.e., one CT exhausting to one HRSG exhausting to one steam turbine generator).

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

- The existing Port Jefferson plant can be expected to continue operating reliably, at a minimum, through the end of the PSA.
- Grid has proposed a repowering configuration that has certain environmental benefits and better operational characteristics compared to the existing Port Jefferson plant.
- The repowering project 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.
- The economic assessment yielded the following major conclusions:
    - 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 Port Jefferson units, are not sufficient to offset the higher PPA fixed costs associated with the repowered units.
    - The Port Jefferson repowering project would result in a total aggregate cost to LIPA's customers of $840 million from 2019 - 2030 and $1.115 billion through 2035, the end of the study period. The total additional costs for an average residential customer through 2030 is $373.
- Because this Study exclusively evaluated repowering the Port Jefferson facility (i.e., it did not compare a repowered Port Jefferson to other options), there may be more optimal scenarios (i.e., providing better efficiency and environmental benefits more cost effectively) when evaluated on a broader, system-wide perspective.

There are many variables (such as the Clean Energy Standard) under development and/or implementation that create uncertainty regarding the optimal characteristics of a power plant and that impact the conclusions above. However, many of these uncertainties are expected to be clarified with time. In conclusion, the proposed repowering configuration is not in the best interests of LIPA's customers and a decision regarding repowering Port Jefferson should be deferred to protect the flexibility required to make an optimal decision. Ongoing monitoring and evaluations should be maintained so that the benefits of repowering can be realized as soon as it is economically viable, or an unexpected event changes Port Jefferson's performance capabilities or end of life considerations.

LAST PAGE OF SECTION 8.

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
BES	Bulk Electric 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
CAIR	2005 Clean Air Interstate Rule
CES	New York's 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 (i.e., Renewable Energy Standard)
CF	Capacity factor; a measure of how much electricity a power plant actually produces as a percentage of how much it is capable of producing in a given time period
CSAPR	2001 Cross-State Air Pollution Rule
CT	Power generation combustion turbine
DMNC	Dependable Maximum Net Capacity. As defined by NYISO, "The sustained maximum net output of a generator, as demonstrated by the performance of a test or through actual operation, averaged over a continuous time period as defined in the ISO Procedures.
EAF	Equivalent Availability Factor. a term defined by the North American Electric Reliability Council that measures the percent of maximum generation available over time
EFORd	Equivalent Forced Outage Rate-Demand; a term defined by the North American Electric Reliability Council considered to be a good indicator of a unit's reliability.
ERP	Energy Resource Plan
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 Power Supply Agreements with LIPA

Term	Definition or Clarification
Grid	Another term for 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. (note – a heat rate calculated using Btu/kWh is equivalent to that calculated by MMBtu/MWh). A lower heat rate indicates a plant is more efficient than one with a higher heat rate; i.e., it requires less fuel to generate comparable electricity
Island Park Energy Center, LLC	A company created and owned by National Grid USA (National Grid) and NextEra Energy Resources, LLC (NextEra) that developed and submitted a proposal to LIPA in July 2014 to repower the E.F. Barrett power plant
KEDLI	KeySpan Energy Delivery Long Island; natural gas supplier
LI DPS	Long Island Branch of the Department of Public Service
LILCO	Long Island Lighting Company, the predecessor utility to LIPA and KeySpan.
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 is in fuel, 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.
NERC	North American Electric Reliability Council
NYSDEC	New York State Department of Environmental Conservation
NYSDPS	New York Department of Public Service
NYISO	The New York Independent System Operator (NYISO)

Term	Definition or Clarification
NYSERDA	New York State Energy Research & Development
O&M	Operations & Maintenance
OSW	Off Shore Wind
Port Jefferson	The Port Jefferson Power Station located in the Town of Brookhaven in the County of Suffolk, New York
PSA	Amended and Restated Power Supply Agreement dated October 12, 2012 and effective May 29, 2013, between LIPA and National Grid. This Agreement pertains to both Barrett and Port Jefferson.
PSC	Public Service Commission
PSEG LI	PSEG Long Island is a subsidiary of Public Service Enterprise Group Incorporated (PSEG) that operates LIPA's transmission and distribution system under a 12-year contract.
PSS	Preliminary Scoping Statement (pursuant to Article 10 requirements)
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
SPDES	State Pollutant Discharge Elimination System
SSCs	Structures, Systems & Components of a power plant (i.e., a plant's physical elements)
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.

CONFIDENTIAL

Repowering Feasibility Study

Appendix A. Benchmarking

CONFIDENTIAL

Repowering Feasibility Study

Appendix A. Benchmarking – Annual

Sargent&Lundy **Report # 14**

National Grid

Created by: R Swanson **Date Created:** 4/04/2017 **Printed:** 4/04/2017

Containing **57 Units** **29 Utilities** **235.25 Unit Years**

Matching the following criteria:

Unit Selection	All Units Incl Own
Unit Type	Fossil-Steam
Date Range	2010 to 2015
Periods	01 to 12
Commercial Date	1/01/1951 to 12/31/1968
MW Rating	150 to 225
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:

EAST RIVER #7	BARRETT #1	BARRETT #2	PORT JEFFERSON #3
PORT JEFFERSON #4	ASTORIA #2	MCKEE RUN #1	EDGEMOOR #4
LEE #3	PORT EVERGLADES #1	PORT EVERGLADES #2	CUTLER #6
INDIAN RIVER #2	BREMO #4	POSSUM POINT #4	KAPP #2
NELSON #3	WILLOW GLEN #1	WILLOW GLEN #2	GORDON EVANS #1
HUTCHINSON #4	STERLINGTON #6	MUSKOGEE #3	HORSESHOE LAKE #6
TULSA #2	TULSA #4	WILKES #1	PLANT X #4
CUNNINGHAM #2	SAM BERTRON #2	SAM BERTRON #1	PARISH #1
PARISH #2	SIM GIDEON #1	SIM GIDEON #2	W. B. TUTTLE #4
V. H. BRAUNIG #1	EAGLE MOUNTAIN #2	COLLINS #1	LAKE CREEK #2
STRYKER CREEK #1	TRINIDAD #6	VALLEY #1	SCATTERGOOD #1
SCATTERGOOD #2	POTRERO 3	AGUA FRIA #3	REDONDO BEACH #5
REDONDO BEACH #6	ALAMITOS #1	ALAMITOS #2	HUNTINGTON BEACH #1
HUNTINGTON BEACH #2	HUNTINGTON BEACH #3	HUNTINGTON BEACH #4	SOUTH BAY #1
SOUTH BAY #2			

Annual Unit Performance Report for Years 2010 - 2015, Periods 01 - 12

Sargent&Lundy

GADS Report (Based on IEEE Standard 762)

Report No.: 14
Printed: 4/04/2017

Unit Years: 235.25

Variable	Mean	Median	Minimum	Maximum	Range	Std. Dev.
Gross Maximum Capacity	181.90	183.83	17.69	249.33	231.64	36.93
Net Maximum Capacity	174.40	175.00	17.00	240.00	223.00	35.75
Gross Dependable Capacity	181.74	183.17	17.69	249.33	231.64	36.80
Net Dependable Capacity	173.83	175.00	17.00	240.00	223.00	35.63
Gross Actual Generation	156,067.00	66,356.00	0.00	706,452.00	706,452.00	171,684.81
Net Actual Generation	145,395.00	53,222.00	-2,706.00	659,327.00	662,033.00	162,085.25
Period Hours	7,704.28	8,764.00	0.00	8,787.00	8,787.00	2,783.84
Unit Service Hours	2,230.95	1,146.26	0.00	7,222.60	7,222.60	2,027.12
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	4,043.44	4,671.63	0.00	8,768.00	8,768.00	2,838.59
# of RSH Occurences	25.22	12.67	0.00	104.83	104.83	24.02
Total Available Hours	6,274.38	7,261.64	0.00	8,768.00	8,768.00	2,602.94
Forced Outage Hours	367.37	130.18	0.00	7,295.67	7,295.67	967.35
# of FOH Occurences	4.01	3.31	0.00	14.00	14.00	3.13
Planned Outage Hours & Ext.	876.90	550.73	0.00	3,757.39	3,757.39	925.55
# of POH Occurences	1.78	1.50	0.00	6.55	6.55	1.44
Maintenance Outage Hours & Ext	185.63	80.61	0.00	1,808.92	1,808.92	262.50
# of MOH Occurences	1.95	1.33	0.00	6.55	6.55	1.69
Total Unavailable Hours	1,429.90	926.39	0.00	7,295.67	7,295.67	1,356.47
# of FD Occurrences	4.69	2.50	0.00	40.00	40.00	8.28
Equiv. Scheduled Derated Hrs	42.84	0.00	0.00	367.08	367.08	70.05
Actual Units Starts	23.25	13.00	0.00	106.17	106.17	22.21
Attempted Unit Starts	23.70	13.50	0.00	107.00	107.00	22.44
Years in Service	52.05	52.00	44.50	58.50	14.00	3.57

Annual Unit Statistics for Years 2010 - 2015, Periods 01 - 12

Sargent&Lundy

GADS Report (Based on IEEE Standard 762)

Report No.: 14

Printed: 4/04/2017

Unit Years: 235.25

Variable	Mean	Median	Minimum	Maximum	Range	Std. Dev.
Planned Outage Factor	11.38	6.29	0.00	42.85	42.85	10.50
Unplanned Outage Factor	7.18	3.81	0.00	96.71	96.71	13.07
Forced Outage Factor	4.77	1.71	0.00	96.71	96.71	12.80
Maint. Outage Factor	2.41	1.04	0.00	20.64	20.64	3.03
Scheduled Outage Factor	13.79	7.23	0.00	43.43	43.43	11.38
Unavailability Factor	18.56	11.12	0.00	96.71	96.71	16.34
Availability Factor	81.44	85.31	0.00	100.00	100.00	26.43
Service Factor	28.96	13.08	0.00	98.83	98.83	25.16
Seasonal Derating Factor	0.20	0.00	0.00	2.51	2.51	0.49
Unit Derating Factor	1.55	0.68	0.00	15.52	15.52	2.29
Equiv. Unavailability Factor	20.11	12.37	0.00	96.71	96.71	16.54
Equiv. Availability Factor	79.70	83.95	0.00	100.00	100.00	26.27
Gross Capacity Factor	11.09	4.53	0.00	40.30	40.30	9.75
Net Capacity Factor	10.78	4.07	-0.31	39.95	40.26	9.69
Gross Output Factor	37.25	38.85	0.00	60.98	60.98	20.07
Net Output Factor	36.23	32.14	-13.53	60.57	74.10	19.38
Equiv. Maint. Outage Factor	2.79	1.16	0.00	20.65	20.65	3.20
Equiv. Planned Outage Factor	11.55	6.36	0.00	42.93	42.93	10.50
Equiv. Forced Outage Factor	6.00	3.16	0.00	96.71	96.71	12.80
Equiv. Scheduled Outage Factor	14.35	7.41	0.00	43.96	43.96	11.48
Equiv. Unplanned Outage Factor	8.55	4.94	0.00	96.71	96.71	13.23
Forced Outage Rate	14.14	6.05	0.00	100.00	100.00	22.32
Forced Outage Rate (demand)	9.22	5.03	0.00	100.00	100.00	14.13
Equiv. Forced Outage Rate	17.68	10.83	0.00	100.00	100.00	22.97
Eq.Forced Outage Rate demand (EFORd	10.60	7.41	0.00	100.00	100.00	14.11
Eq Unplanned Outage Rate (EUOR)	24.15	19.53	0.00	100.00	100.00	24.63
Average Run Time	95.95	59.73	0.00	3,504.00	3,504.00	488.95
Starting Reliability	98.10	98.32	0.00	100.00	100.00	35.76

Units Included in Study # 14

Sargent&Lundy

GADS Report (Based on IEEE Standard 762)

Utility	Unit Code	Region	Unit Name	Commercial Date
108 CONSOLIDATED EDISON CO. OF NY				
	133	NPCC	EAST RIVER #7	6/24/1955
113 National Grid (Keyspan Energy)				
	101	NPCC	BARRETT #1	10/25/1956
	102	NPCC	BARRETT #2	10/24/1963
	133	NPCC	PORT JEFFERSON #3	11/08/1958
	134	NPCC	PORT JEFFERSON #4	11/11/1960
151 US Power Generating Company				
	102	NPCC	ASTORIA #2	3/23/1954
203 DELAWARE MUNICIPAL UTILITIES				
	181	RFC	MCKEE RUN #1	3/24/1962
250 CALPINE CORP - RFC				
	114	RFC	EDGEMOOR #4	4/14/1966
307 DUKE POWER CO.				
	143	SERC	LEE #3	12/12/1958
308 FLORIDA POWER & LIGHT CO.				
	113	FRCC	PORT EVERGLADES #1	5/27/1960
	114	FRCC	PORT EVERGLADES #2	4/23/1961
	124	FRCC	CUTLER #6	8/22/1955
317 ORLANDO UTILITIES/GenOn Energy				
	112	FRCC	INDIAN RIVER #2	9/10/1964
328 VIRGINIA POWER				
	102	SERC	BREMO #4	8/08/1958
	119	SERC	POSSUM POINT #4	4/18/1962
607 ALLIANT ENERGY (INTERSTATE PWR)				
	107	MRO	KAPP #2	3/02/1967
717 GULF STATES UTILITIES CO.				
	133	SERC	NELSON #3	3/29/1960
	151	SERC	WILLOW GLEN #1	3/30/1960
	152	SERC	WILLOW GLEN #2	1/29/1964
719 Westar Energy (KGE)				
	109	SPP	GORDON EVANS #1	6/01/1961
720 Westar Energy (KPL)				
	107	SPP	HUTCHINSON #4	5/16/1965

Utility	Unit Code	Region	Unit Name	Commercial Date
722 LOUISIANA POWER & LIGHT CO.				
	102	SERC	STERLINGTON #6	5/28/1958
729 OKLAHOMA GAS AND ELECTRIC CO.				
	109	SPP	MUSKOGEE #3	5/26/1956
	110	SPP	HORSESHOE LAKE #6	3/22/1958
730 AMERICAN ELECTRIC POWER WEST				
	132	SPP	TULSA #2	11/21/1956
	134	SPP	TULSA #4	5/31/1958
732 AMERICAN ELECTRIC POWER WEST				
	110	SPP	WILKES #1	11/24/1964
734 XCEL ENERGY				
	113	SPP	PLANT X #4	7/01/1964
	115	SPP	CUNNINGHAM #2	7/01/1965
840 NRG Texas, LLC				
	120	ERCOT	SAM BERTRON #2	4/01/1956
	121	ERCOT	SAM BERTRON #1	6/01/1958
	122	ERCOT	PARISH #1	6/01/1958
	123	ERCOT	PARISH #2	12/20/1958
854 LOWER COLORADO RIVER AUTHORITY				
	101	ERCOT	SIM GIDEON #1	5/15/1965
	102	ERCOT	SIM GIDEON #2	1/15/1968
868 CPS Energy				
	111	ERCOT	W. B. TUTTLE #4	3/19/1963
	112	ERCOT	V. H. BRAUNIG #1	3/28/1966
879 EXELON GENERATION, LLC				
	132	ERCOT	EAGLE MOUNTAIN #2	7/21/1954
880 Luminant Power				
	111	ERCOT	COLLINS #1	5/01/1955
	132	ERCOT	LAKE CREEK #2	7/09/1959
	151	ERCOT	STRYKER CREEK #1	6/26/1958
	172	ERCOT	TRINIDAD #6	4/26/1964
	181	ERCOT	VALLEY #1	11/16/1962
920 LOS ANGELES DEPT. OF WATER/POWER				
	121	WECC	SCATTERGOOD #1	12/07/1958
	122	WECC	SCATTERGOOD #2	7/01/1959

Utility	Unit Code	Region	Unit Name	Commercial Date
928 MIRANT				
	133	WECC	POTRERO 3	12/01/1965
944 SALT RIVER PROJECT				
	113	WECC	AGUA FRIA #3	4/01/1961
967 AES - REDONDO BEACH				
	105	WECC	REDONDO BEACH #5	9/23/1954
	106	WECC	REDONDO BEACH #6	5/22/1957
971 AES-ALAMITOS LLC				
	121	WECC	ALAMITOS #1	6/28/1956
	122	WECC	ALAMITOS #2	1/08/1957
	136	WECC	HUNTINGTON BEACH #1	5/01/1958
	137	WECC	HUNTINGTON BEACH #2	10/02/1958
	138	WECC	HUNTINGTON BEACH #3	10/26/1960
	139	WECC	HUNTINGTON BEACH #4	4/15/1961
987 Dynegy Power				
	105	WECC	SOUTH BAY #1	7/23/1960
	106	WECC	SOUTH BAY #2	6/16/1962

CONFIDENTIAL

Repowering Feasibility Study

Benchmarking – June, July & August

Sargent&Lundy **Report # 15**

National Grid

Created by: R Swanson **Date Created:** 4/04/2017 **Printed:** 4/04/2017

Containing **56 Units** **28 Utilities** **59.08 Unit Years**

Matching the following criteria:

Unit Selection	All Units Incl Own
Unit Type	Fossil-Steam
Date Range	2010 to 2015
Periods	06 to 08
Commercial Date	1/01/1951 to 12/31/1968
MW Rating	150 to 225
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:

EAST RIVER #7	BARRETT #1	BARRETT #2	PORT JEFFERSON #3
PORT JEFFERSON #4	ASTORIA #2	MCKEE RUN #1	EDGEMOOR #4
LEE #3	PORT EVERGLADES #1	PORT EVERGLADES #2	CUTLER #6
INDIAN RIVER #2	BREMO #4	POSSUM POINT #4	NELSON #3
WILLOW GLEN #1	WILLOW GLEN #2	GORDON EVANS #1	HUTCHINSON #4
STERLINGTON #6	MUSKOGEE #3	HORSESHOE LAKE #6	TULSA #2
TULSA #4	WILKES #1	PLANT X #4	CUNNINGHAM #2
SAM BERTRON #2	SAM BERTRON #1	PARISH #1	PARISH #2
SIM GIDEON #1	SIM GIDEON #2	W. B. TUTTLE #4	V. H. BRAUNIG #1
EAGLE MOUNTAIN #2	COLLINS #1	LAKE CREEK #2	STRYKER CREEK #1
TRINIDAD #6	VALLEY #1	SCATTERGOOD #1	SCATTERGOOD #2
POTRERO 3	AGUA FRIA #3	REDONDO BEACH #5	REDONDO BEACH #6
ALAMITOS #1	ALAMITOS #2	HUNTINGTON BEACH #1	HUNTINGTON BEACH #2
HUNTINGTON BEACH #3	HUNTINGTON BEACH #4	SOUTH BAY #1	SOUTH BAY #2

Annual Unit Performance Report for Years 2010 - 2015, Periods 06 - 08

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

Report No.: 15
Printed: 4/04/2017
Unit Years: 59.08

Variable	Mean	Median	Minimum	Maximum	Range	Std. Dev.
Gross Maximum Capacity	181.82	185.00	17.68	249.33	231.65	35.83
Net Maximum Capacity	174.36	176.50	17.00	240.00	223.00	34.70
Gross Dependable Capacity	181.67	183.25	17.68	249.33	231.65	35.71
Net Dependable Capacity	173.78	175.00	17.00	240.00	223.00	34.60
Gross Actual Generation	62,734.00	32,312.00	0.00	260,214.00	260,214.00	63,318.42
Net Actual Generation	58,590.00	30,860.50	-701.00	244,563.00	245,264.00	59,625.07
Period Hours	1,951.31	2,208.00	0.00	2,211.43	2,211.43	706.13
Unit Service Hours	807.07	469.62	0.00	2,130.10	2,130.10	654.51
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	960.19	1,009.83	0.00	2,208.00	2,208.00	760.03
# of RSH Occurences	11.56	5.00	0.00	50.67	50.67	12.47
Total Available Hours	1,767.26	2,105.62	0.00	2,211.43	2,211.43	718.04
Forced Outage Hours	102.22	31.25	0.00	1,960.00	1,960.00	273.00
# of FOH Occurences	1.31	0.75	0.00	4.50	4.50	1.13
Planned Outage Hours & Ext.	40.61	0.00	0.00	616.47	616.47	105.42
# of POH Occurences	0.09	0.00	0.00	1.17	1.17	0.24
Maintenance Outage Hours & Ext	41.22	14.37	0.00	277.01	277.01	58.15
# of MOH Occurences	0.69	0.50	0.00	4.50	4.50	0.79
Total Unavailable Hours	184.05	68.13	0.00	1,960.00	1,960.00	304.83
# of FD Occurrences	1.64	1.00	0.00	17.00	17.00	2.61
Equiv. Scheduled Derated Hrs	14.92	0.00	0.00	178.09	178.09	33.80
Actual Units Starts	11.37	5.00	0.00	52.00	52.00	12.21
Attempted Unit Starts	11.52	5.00	0.00	52.17	52.17	12.28
Years in Service	52.05	52.25	44.50	58.50	14.00	3.57

Annual Unit Statistics for Years 2010 - 2015, Periods 06 - 08

Sargent&Lundy

GADS Report (Based on IEEE Standard 762)

Report No.: 15

Printed: 4/04/2017

Unit Years: 59.08

Variable	Mean	Median	Minimum	Maximum	Range	Std. Dev.
Planned Outage Factor	2.08	0.00	0.00	27.92	27.92	4.77
Unplanned Outage Factor	7.35	3.08	0.00	100.00	100.00	14.15
Forced Outage Factor	5.24	1.44	0.00	100.00	100.00	14.00
Maint. Outage Factor	2.11	0.70	0.00	12.55	12.55	2.67
Scheduled Outage Factor	4.19	0.83	0.00	30.15	30.15	6.09
Unavailability Factor	9.43	3.29	0.00	100.00	100.00	15.19
Availability Factor	90.57	96.16	0.00	100.00	100.00	29.86
Service Factor	41.36	21.27	0.00	100.00	100.00	31.00
Seasonal Derating Factor	0.26	0.00	0.00	3.15	3.15	0.60
Unit Derating Factor	2.30	0.39	0.00	24.67	24.67	3.92
Equiv. Unavailability Factor	11.73	4.42	0.00	100.00	100.00	15.82
Equiv. Availability Factor	88.01	94.75	0.00	100.00	100.00	29.65
Gross Capacity Factor	17.64	9.49	0.00	58.93	58.93	14.18
Net Capacity Factor	17.17	8.98	-0.38	58.30	58.68	14.05
Gross Output Factor	41.51	42.78	0.00	79.80	79.80	21.95
Net Output Factor	40.50	40.66	-0.38	73.57	73.95	20.62
Equiv. Maint. Outage Factor	2.78	0.85	0.00	15.15	15.15	3.32
Equiv. Planned Outage Factor	2.17	0.00	0.00	27.92	27.92	4.76
Equiv. Forced Outage Factor	7.07	2.33	0.00	100.00	100.00	14.43
Equiv. Scheduled Outage Factor	4.96	1.22	0.00	30.15	30.15	6.33
Equiv. Unplanned Outage Factor	9.55	3.87	0.00	100.00	100.00	14.83
Forced Outage Rate	11.24	4.20	0.00	100.00	100.00	21.13
Forced Outage Rate (demand)	7.48	2.69	0.00	37.50	37.50	8.40
Equiv. Forced Outage Rate	15.07	8.30	0.00	100.00	100.00	21.91
Eq.Forced Outage Rate demand (EFORd	9.35	3.46	0.00	37.57	37.57	9.39
Eq Unplanned Outage Rate (EUOR)	20.09	14.91	0.00	100.00	100.00	22.63
Average Run Time	70.95	53.77	0.00	1,408.27	1,408.27	349.05
Starting Reliability	98.76	100.00	0.00	100.00	100.00	37.78

Units Included in Study # 15

Sargent&Lundy

GADS Report (Based on IEEE Standard 762)

Utility	Unit Code	Region	Unit Name	Commercial Date
108 CONSOLIDATED EDISON CO. OF NY				
	133	NPCC	EAST RIVER #7	6/24/1955
113 National Grid (Keyspan Energy)				
	101	NPCC	BARRETT #1	10/25/1956
	102	NPCC	BARRETT #2	10/24/1963
	133	NPCC	PORT JEFFERSON #3	11/08/1958
	134	NPCC	PORT JEFFERSON #4	11/11/1960
151 US Power Generating Company				
	102	NPCC	ASTORIA #2	3/23/1954
203 DELAWARE MUNICIPAL UTILITIES				
	181	RFC	MCKEE RUN #1	3/24/1962
250 CALPINE CORP - RFC				
	114	RFC	EDGEMOOR #4	4/14/1966
307 DUKE POWER CO.				
	143	SERC	LEE #3	12/12/1958
308 FLORIDA POWER & LIGHT CO.				
	113	FRCC	PORT EVERGLADES #1	5/27/1960
	114	FRCC	PORT EVERGLADES #2	4/23/1961
	124	FRCC	CUTLER #6	8/22/1955
317 ORLANDO UTILITIES/GenOn Energy				
	112	FRCC	INDIAN RIVER #2	9/10/1964
328 VIRGINIA POWER				
	102	SERC	BREMO #4	8/08/1958
	119	SERC	POSSUM POINT #4	4/18/1962
717 GULF STATES UTILITIES CO.				
	133	SERC	NELSON #3	3/29/1960
	151	SERC	WILLOW GLEN #1	3/30/1960
	152	SERC	WILLOW GLEN #2	1/29/1964
719 Westar Energy (KGE)				
	109	SPP	GORDON EVANS #1	6/01/1961
720 Westar Energy (KPL)				
	107	SPP	HUTCHINSON #4	5/16/1965
722 LOUISIANA POWER & LIGHT CO.				
	102	SERC	STERLINGTON #6	5/28/1958

Utility	Unit Code	Region	Unit Name	Commercial Date
729 OKLAHOMA GAS AND ELECTRIC CO.				
	109	SPP	MUSKOGEE #3	5/26/1956
	110	SPP	HORSESHOE LAKE #6	3/22/1958
730 AMERICAN ELECTRIC POWER WEST				
	132	SPP	TULSA #2	11/21/1956
	134	SPP	TULSA #4	5/31/1958
732 AMERICAN ELECTRIC POWER WEST				
	110	SPP	WILKES #1	11/24/1964
734 XCEL ENERGY				
	113	SPP	PLANT X #4	7/01/1964
	115	SPP	CUNNINGHAM #2	7/01/1965
840 NRG Texas, LLC				
	120	ERCOT	SAM BERTRON #2	4/01/1956
	121	ERCOT	SAM BERTRON #1	6/01/1958
	122	ERCOT	PARISH #1	6/01/1958
	123	ERCOT	PARISH #2	12/20/1958
854 LOWER COLORADO RIVER AUTHORITY				
	101	ERCOT	SIM GIDEON #1	5/15/1965
	102	ERCOT	SIM GIDEON #2	1/15/1968
868 CPS Energy				
	111	ERCOT	W. B. TUTTLE #4	3/19/1963
	112	ERCOT	V. H. BRAUNIG #1	3/28/1966
879 EXELON GENERATION, LLC				
	132	ERCOT	EAGLE MOUNTAIN #2	7/21/1954
880 Luminant Power				
	111	ERCOT	COLLINS #1	5/01/1955
	132	ERCOT	LAKE CREEK #2	7/09/1959
	151	ERCOT	STRYKER CREEK #1	6/26/1958
	172	ERCOT	TRINIDAD #6	4/26/1964
	181	ERCOT	VALLEY #1	11/16/1962
920 LOS ANGELES DEPT. OF WATER/POWER				
	121	WECC	SCATTERGOOD #1	12/07/1958
	122	WECC	SCATTERGOOD #2	7/01/1959
928 MIRANT				
	133	WECC	POTRERO 3	12/01/1965

Units Included in Study # 15

Sargent&Lundy

GADS Report (Based on IEEE Standard 762)

Utility	Unit Code	Region	Unit Name	Commercial Date
944 SALT RIVER PROJECT				
	113	WECC	AGUA FRIA #3	4/01/1961
967 AES - REDONDO BEACH				
	105	WECC	REDONDO BEACH #5	9/23/1954
	106	WECC	REDONDO BEACH #6	5/22/1957
971 AES-ALAMITOS LLC				
	121	WECC	ALAMITOS #1	6/28/1956
	122	WECC	ALAMITOS #2	1/08/1957
	136	WECC	HUNTINGTON BEACH #1	5/01/1958
	137	WECC	HUNTINGTON BEACH #2	10/02/1958
	138	WECC	HUNTINGTON BEACH #3	10/26/1960
	139	WECC	HUNTINGTON BEACH #4	4/15/1961
987 Dynegy Power				
	105	WECC	SOUTH BAY #1	7/23/1960
	106	WECC	SOUTH BAY #2	6/16/1962

Repowering Feasibility Study

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 I 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]	[illegible]	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 o[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				
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 Barrett Station is in excess of [redacted]
Material Condition/Major Systems				
Fuel Delivery	Forced Air	Environmental		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.
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 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.
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	Olive	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				Comments: The 2014 thru 2018 Capital Budget for the Northport Station is in excess o[redacted]
Base	Outage	Capital		
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

Red	Not without Major Intervention
Yellow	Threatened without Minor Intervention
White	Yes
Green	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				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 Northport Station is in excess of [redacted]
Base	Outage	Capital		
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	Not without Major Intervention
Yellow	Threatened without Minor Intervention
White	Yes
Green	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				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 Northport Station is in excess of [redacted]
Base	Outage	Capital		
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 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.
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

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				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 Port Jefferson Station is in excess of [redacted]
Base	Outage	Capital		
Material Condition/Major Systems				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.
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 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.
Turbines	Generators	Boilers		
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		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.
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 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.
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 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

(red)	Not without Major Intervention	(yellow)	Threatened without Minor Intervention	(white)	Yes	(gold)	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 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 station is [redacted]
Base	Outage	Capital		
Material Condition/Major Systems				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.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				All Major Components are in satisfactory condition.
Comb. Turbines	Compressors	Generators		
Breakers	Transformers	Stacks		
Inlet ducts				

Will Meet Contractual Performance Requirements 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

Red	Not without Major Intervention
Yellow	Threatened without Minor Intervention
White	Yes
Gold	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 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 station is in excess of [redacted]
Base	Outage	Capital		
Material Condition/Major Systems				Satisfactory. These units have recently been improved by adding water injection for NOx control. 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. Stacks and inlet ducts requiring attention are addressed in the Capital Projects five (5) year plan.
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

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

Not without Major Intervention	Threatened without Minor Intervention	Yes	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

Red	Not without Major Intervention
Yellow	Threatened without Minor Intervention
White	Yes
Gold	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 CO2 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 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 station is in excess of [redacted]
Base	Outage	Capital		
Material Condition/Major Systems				Satisfactory. Replacement of bulk CO2 storage systems planned as Capital Improvement.
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				
Material Condition/Major Components				Satisfactory. Replacement of exhaust stacks currently in progress as Capital Improvement project.
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

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 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.
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

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

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.

1979 - Mid 1980s

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.

Late 1980s

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, interim 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".

<u>Mid-Late 1990s</u>

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.

2000-2003

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.

2004-2006

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.

2009-2012 (SOFA Outages)

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

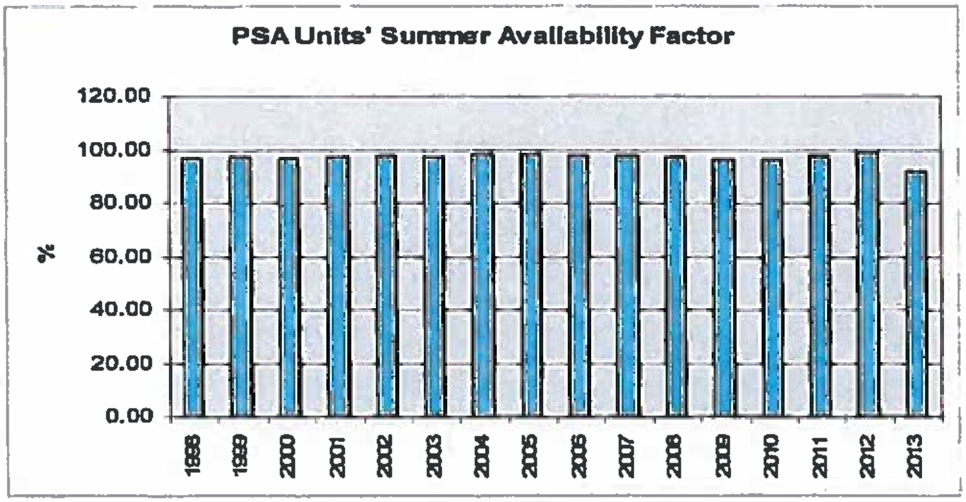
b. **Northport 1 High Energy Piping Condition Assessment 2013 Final**
c. **Northport 2 High Energy Piping Condition Assessment (post 2012-2013 outage)**
d. **Northport 3 High Energy Piping Condition Assessment 2013 Final with Priority**
e. **Northport 4 High Energy Piping Condition Assessment 2012-2014**
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**

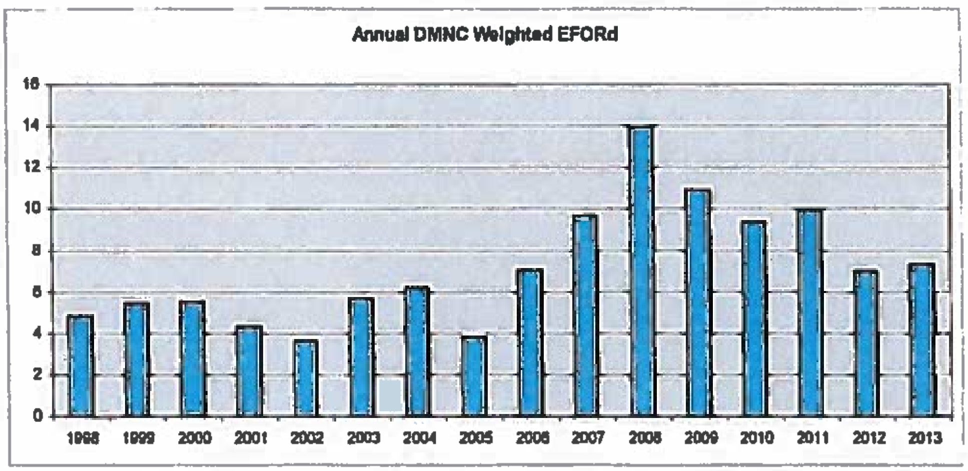
4. **Port Jefferson Power Station Documentation**
    a. **PJ 3 1999 Field Boresonic Inspection**
    b. **PJ 3 2007 LPDF Boresonic Inspection**
    c. **PJ 3 2007 IPLPSF Boresonic Inspection**
    d. **PJ 3 2007 HP Boresonic Inspection**
    e. **PJ 4 2010 HP IPLPSF LPDF Boresonic Inspection**
    f. **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**

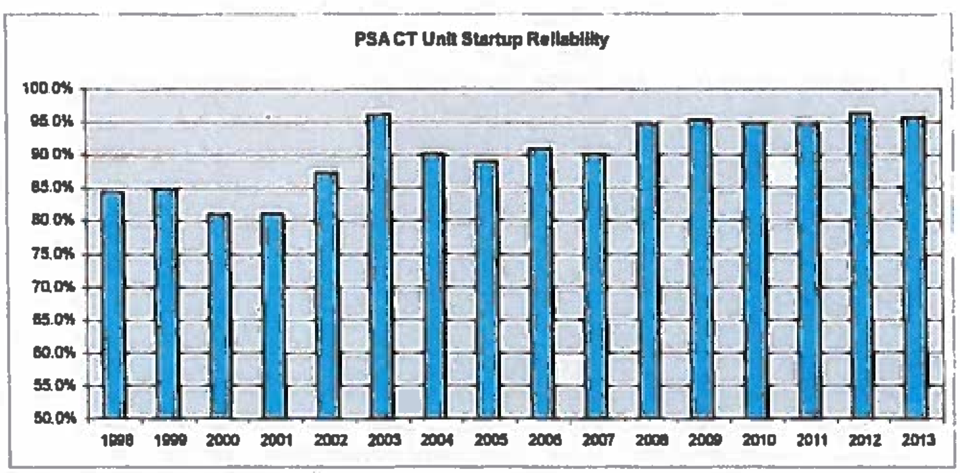
    e. Final Shop Report 018859 Nat Grid GG4A P675476
    f. EFBGT 8 HPI Borescope 2008
6. Holtsville GT Site Documentation
    a. Holtsville 686604 HSI
7. Port Jefferson GT Site Documentation
    a. LM6000PC – 191422
    b. LM6000PC – 191412
8. Wading River GT Site Specific
    a. WR3 Borescope Report 03-12-13
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

Repowering Feasibility Study

Appendix C. 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 Port Jefferson. 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 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 publically 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) 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 pumping costs exceed the incremental savings that result from peak shaving or the reservoir 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 pumping 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 off line 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.

LAST PAGE OF APPENDIX C.

Repowering Feasibility Study

Appendix D. 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.

LAST PAGE OF APPENDICES.))