



**DRAFT**

## **Repowering Feasibility Study E. F. Barrett Power Station**



Draft as of April 19, 2017



## CONTENTS

<u>Section</u>	<u>Page</u>
<b>EXECUTIVE SUMMARY .....</b>	<b>ES-1</b>
<b>1. SCOPE, OBJECTIVES &amp; APPROACH .....</b>	<b>1-1</b>
1.1 Scope & Objectives.....	1-1
1.2 Approach .....	1-2
<b>2. BACKGROUND &amp; INPUTS.....</b>	<b>2-1</b>
2.1 Current Plant Description.....	2-1
2.2 Current Plant Operation .....	2-2
2.3 Condition of Existing Facilities.....	2-5
<b>3. REPOWERING CONFIGURATION.....</b>	<b>3-1</b>
<b>4. ENGINEERING &amp; ENVIRONMENTAL ANALYSIS .....</b>	<b>4-1</b>
4.1 Engineering Considerations .....	4-1
4.1.1 Proposed Repowering Option.....	4-1
4.1.2 Repowered Unit Operating Performance.....	4-3
4.1.3 Fuel Supply, Delivery and Storage.....	4-3
4.1.4 Electric Interconnection.....	4-4
4.2 Transmission System .....	4-4
4.2.1 Site Exit Limitation .....	4-4
4.2.2 NERC Planning Standard .....	4-5
4.2.3 Conclusion.....	4-6
4.3 Environmental Considerations .....	4-6
4.3.1 Permitting.....	4-6
4.3.2 Permitting Studies .....	4-9
4.3.3 Repowering Plant Air Emissions and Water Issues.....	4-10



## CONTENTS

<u>Section</u>	<u>Page</u>
4.4 Constructability .....	4-11
4.4.1 Equipment Delivery.....	4-11
4.4.2 Laydown Space .....	4-11
4.4.3 Impact on Existing Facilities from Construction Activities .....	4-12
4.5 Storm Protection.....	4-12
<b>5. REPOWERING ECONOMIC VIABILITY.....</b>	<b>5-1</b>
5.1 Ramp Down and Repowering Provisions .....	5-1
5.2 Economic Analysis.....	5-2
5.2.1 Cost and Emission Impacts.....	5-2
5.2.2 Modeling Considerations.....	5-2
5.2.3 Results .....	5-3
5.3 Site Acquisition Options .....	5-6
5.3.1 PSA Article 10 Capacity Ramp Down .....	5-7
5.3.2 Schedule F – Grant of Future Rights .....	5-7
<b>6. A CHANGING ENVIRONMENT.....</b>	<b>6-1</b>
6.1 State Initiatives.....	6-1
6.2 LIPA Commitments .....	6-2
6.3 Existing Contracts, & Need for Flexibility .....	6-3
6.4 Peak Load Forecasts.....	6-3
<b>7. COMMUNITY IMPACTS.....</b>	<b>7-1</b>
7.1 Jobs.....	7-1
7.2 Taxes .....	7-1
<b>8. CONCLUSIONS.....</b>	<b>8-1</b>



## CONTENTS

<u>Section</u>	<u>Page</u>
<b>9. ACRONYMS AND ABBREVIATIONS .....</b>	<b>9-1</b>
<b>APPENDIX A. PREVIOUS REPOWERING AND REFERENCED STUDIES.....</b>	<b>A-1</b>
<b>APPENDIX B. BENCHMARKING.....</b>	<b>B-1</b>
<b>APPENDIX C. RCMT CONDITION ASSESSMENT REPORT (REDACTED).....</b>	<b>C-1</b>
<b>APPENDIX D. PRODUCTION COST METHODOLOGY.....</b>	<b>D-1</b>
<b>APPENDIX E. MARKET FORECASTING METHODOLOGY.....</b>	<b>E-1</b>



## TABLES AND FIGURES

<u>Table or Figure</u>	<u>Page</u>
Table 3-1 — Barrett Repowering Attributes Summary .....	3-2
Table 4-1 — Disposition of Major Plant Components .....	4-1
Table 4-2 — List of Permits and Approvals .....	4-7
Table 6-1 — Ongoing State Initiatives .....	6-2
Table 7-1 — Disproportionate Legacy Property Taxes .....	7-2
Figure 2-1 — Steam Units Historical Capacity Factors .....	2-3
Figure 2-2 — Summer Equivalent Availability Factor .....	2-4
Figure 5-1 — Increase in Annual Costs Associated with Barrett Repowering .....	5-4
Figure 5-2 — Barrett Capacity Factor Trend .....	5-6
Figure 6-1 — Existing Capacity Resources and Contract Expiration .....	6-3
Figure 6-2 — LIPA Peak Load Forecasts .....	6-4



## 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<sup>1</sup>), 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)<sup>2</sup> related to repowering. (Appendix A lists previous and/or related studies performed as part of LIPA’s resource planning activities.)

As required by the Bill, this Study evaluates repowering the Barrett 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 Barrett, and possibly at lower cost. For example, in lieu of repowering Barrett, an alternate investment to build a new renewable energy facility, or a new simple or combined cycle facility at a different location, or retiring Barrett and upgrading the proximate transmission system infrastructure (thereby eliminating all local power plant emissions), may be more cost effective and environmentally friendly than repowering Barrett. Or, a Barrett 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

---

<sup>1</sup> Throughout this Study, “Grid” is used to identify any of the following entities/terms: National Grid USA, National Grid, National Grid Generation, GENCO, and Island Park Energy Center, LLC (a company created and jointly owned by National Grid USA and NextEra Energy Resources LLC). Grid owns the legacy LILCO power generating stations.

<sup>2</sup> 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.



options available to the Authority that might achieve the same or greater benefits, at a lower cost, than a Barrett repowering. A full analysis of these options, however, falls outside the scope of this Study.

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 Barrett 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 Barrett 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.
- As measured over the first 10 years (2021-2030) that the repowered unit is in service, the total additional cost to LIPA's customers is \$1.145 billion and over the course of the Study period (thru 2035) the total cost to LIPA's customers is \$1.302 billion.<sup>3</sup>
- The total additional cost for an average residential customer over the first 10 years is \$514.<sup>4</sup>
- The decline in natural gas prices since 2008 makes repowering more uneconomic.
- The five-year average capacity factor<sup>5</sup> (2012 – 2016) for the Barrett steam units was 38.2%. This compares to a high of 54% in the late 1990's. The station's combustion turbines capacity factors ranged between 2% - 7% during the same period. 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 Barrett units are well maintained, reliable for their age, and with reasonable projected capital and operations and

<sup>3</sup> Cost impacts are measured against the Integrated Resource Plan Reference case.

<sup>4</sup> Ibid

<sup>5</sup> A capacity factor of 100% means that a plant would be operating at its full capacity every hour of the year.



maintenance expenditures can maintain their reliability for the foreseeable future<sup>6</sup>. The condition assessment results are consistent with recent operating performance. For example, during the period 2010-2015 the steam units' annual Equivalent Forced Outage Rate-demand<sup>7</sup> (EFORd), one of the North American Electric Reliability Corporation's (NERC's) best indicators of operational reliability, averaged 4.4%. Overall, Barrett'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 Barrett 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 MWs less than the forecast for 2030 prepared in 2013, resulting in a peak load forecast reduction that is over two and one-half times the size of the proposed Barrett combined cycle units. At present, LIPA is forecasted to have surplus generation capacity until at least 2035. These factors and the continuation of such trends could render alternative generation configurations at the Barrett site or other sites more attractive to LIPA's customers.
- The Study, per Grid's proposal, assumes property taxes of \$29 million per year, which, while less than current property taxes of \$36 million per year (and rising) for the existing plant, is not adequate to remove the economic disincentive for further investing in legacy power plant sites such

<sup>6</sup> "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.

<sup>7</sup> The lower the EFORd, the better the performance.





as the Barrett site. Furthermore, the proposed property taxes are approximately 50% higher on a \$/MW basis than that paid by LIPA 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 Barrett site for the purpose of constructing new generation. If a decision were made to build units at the Barrett 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 existing Barrett power station is in the Town of Hempstead, Nassau County, New York. It is comprised of two 195 MW dual-fuel (i.e., the units are primarily fueled with natural gas but can burn No. 6 fuel oil) steam units that went into commercial operation in 1956 and 1963, and eleven (11) simple cycle, dual fueled, combustion turbines (CTs) comprised of seven (7) 15 MW General Electric CTs and four (4) 40 MW Pratt & Whitney CTs with a total capacity of approximately 265 MWs. The simple cycle CT units went into commercial operation in 1970 and 1971. Barrett steam units have heat rates (i.e., a measure of plant efficiency) of approximately 10,500 Btu/ kilowatt-hour (Btu/kWh). Notwithstanding Barrett's age, the results of an independent plant condition assessment conducted in late 2014 indicate that the units are well maintained, reliable for their age and can, with reasonable projected capital, operations and maintenance expenditures, maintain that reliability for the foreseeable future. Continued expenditures on the existing units were assumed in evaluating the benefits of repowering with new units. With respect to Section 316b of the Federal Clean Water Act (i.e., aquatic protection), the Barrett steam units are operating under their current permit, which was extended under the State Administrative Procedures Act (SAPA). It was assumed for purposes of this Study that compliance with 316b by the existing Barrett steam units would be met via the installation of variable speed drives on the circulating water pumps and replacement of the traveling screens by fish friendly screens. The assumed solution (variable speed drives and fish friendly screens) for Barrett is what Grid proposed as the Best Technology Available (BTA) in permit proceedings and is similar to that accepted and implemented at Port Jefferson and Northport.

SO<sub>2</sub> emissions from the plant are directly proportional to the sulfur content of the residual fuel oil; the current regulatory limit is a maximum sulfur content of 0.37%. For Unit 1, there is no unit specific NO<sub>x</sub> emission rate limit, however, there is a NO<sub>x</sub> Reasonably Available Control Technology (RACT) regulatory target of 0.15 lbs/MMBtu regardless of fuel. On gas, this unit typically operates 40-50% below the target. Unit 2 does have



NO<sub>x</sub> emission rate limits, based on a 24-hour average, of 0.1 lbs/MMBtu on gas and 0.2 lbs/MMBtu when combusting oil. On gas, Unit 2 normally operates about 50% below the limit. Both units have burned a very limited amount of oil, but emissions would be expected to be in the range of 0.15 lbs/MMBtu NO<sub>x</sub>.

## 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 Barrett, however, Grid<sup>8</sup> studied two repowering configurations, each of which would entail retiring the 2 steam units (boilers and steam turbines), and some or all the GE CTs, and two of the four Pratt & Whitney CTs. Therefore, this Study is more properly understood as constructing new generation on an existing site.

The options offered by Grid were:

- **Option A:** Two ‘1x1x1’<sup>9</sup> units based on an advanced design combustion turbine in a combined cycle configuration, totaling 637 megawatts (MW)
- **Option B:** One ‘1x1x1’ unit based on an advanced design combustion turbine in a combined cycle configuration and a simple cycle unit, totaling 532 MW

While both proposals had similar pricing characteristics, only Option A was evaluated as that configuration’s proposed size is closer to the total capacity of the existing facilities being retired.

The proposed repowered plant offers fuel and emissions benefits relative to the existing facility. Environmentally, the repowered units lower CO<sub>2</sub> emission rates (lbs/MWh) by approximately 35%, lower NO<sub>x</sub> emission rates by 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 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 Barrett site, though, would be offset by

<sup>8</sup> Properly, Island Park Energy Center, LLC, (Island Park), co-owned by National Grid and NextEra Energy LLC, developed the cost proposals for both repowering options. However, “Grid” will be used throughout the report when referring to the developer.

<sup>9</sup> As used in this Study, a 1x1x1 configuration consists of one CT generator exhausting into one heat recovery steam generator that provides steam to one steam generator.



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 Barrett.

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, however, the repowered units would increase overall costs to LIPA ratepayers as the total 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, though, 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 Barrett, 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 and would have impacts on transmission and distribution systems. Specifically, 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 Barrett 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 Barrett 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 MWs while the most recent peak load projection for 2030 is 5,341 MWs, a reduction of 1,699 MWs, or over two



and one-half times the size of the proposed repowering project. The forecasted peak load reductions results in a projected surplus of generation capacity until 2035.

## **Cost of the Proposed Plant**

Grid developed two cost proposals for both repowering options, the proposals representing 30-year and 40-year power purchase agreements (“PPAs”). As noted, the larger sized repowering option was evaluated but only for the 30-year PPA option. 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. In addition, the need for transmission reinforcements was examined but, as previously noted, because the proposed plant is the approximate size of the existing facility, and allowing for currently planned transmission upgrades, those costs were determined to be minor.

The evaluation of the Barrett repowering proposal was based on a model that is used for LIPA’s financial projections. A key feature of the proposal was that the repowered unit would have annual taxes of \$29 million per year, which is \$7 million per year less than the current level of taxes for the existing units but approximately 50% more than what LIPA would pay for new generation of similar size in other parts of Long Island.

## **Conclusion**

The Authority has determined that a repowering of the Barrett 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 Barrett 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 Barrett (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



## Repowering Feasibility Study

ES-8  
*Executive Summary*  
**Draft**

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 the E. F. Barrett Power Station (Barrett). 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 & OBJECTIVES

The scope of the Study was to perform an engineering, environmental, permitting and cost feasibility analysis of the potential repowering of Barrett. While it does include the system-wide energy and capacity impacts that result from such a repowering, and makes assumptions regarding important local issues such as property taxes, the 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 Barrett 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 Barrett, and possibly at lower cost. For example, in lieu of repowering Barrett, 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 Barrett and upgrading the proximate transmission system infrastructure (thereby eliminating all local power plant emissions), may be more cost effective and environmentally friendly than repowering Barrett. Or, simply, a Barrett 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 Barrett repowering. but that a full analysis of these options falls outside the scope of this Study.

The objective of the Study was to provide the LIPA Board of Trustees with necessary background and analyses regarding the potential repowering of Barrett. As stated in the Bill, the Study is intended to support LIPA in determining if repowering "...is in the best interests of its ratepayers and will enhance 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 Barrett technically feasible and economically viable?
- Is now the optimum time for deciding when and how to repower Barrett, 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 Barrett 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.<sup>10</sup> 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

Barrett is located on an approximately 127-acre property located in the Town of Hempstead, Nassau County, New York. The property is accessed from Daly Boulevard to the north and from Long Beach Road to the south. The Long Island Railroad (LIRR) transects the western portion of the property in a north/south direction.

Barrett is currently operated and maintained as an active electric generation station. It comprises two steam units, each 195 MWs, that went into commercial operation in 1956 and 1963, and eleven (11) simple cycle combustion turbine units. Both steam units are equipped with General Electric tandem compound reheat triple flow low pressure (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. Barrett Unit 1 originally burned coal and both units are now equipped to fire natural gas or low sulfur residual fuel oil. The plant is adjacent to the Transco natural gas pipeline and the primary fuel is natural gas.

Balance of Plant (BOP) structures, systems and components (SSCs) located south of the discharge canal include a No. 6 fuel oil tank farm, fuel oil offloading facilities and an industrial wastewater treatment facility. The fuel oil tank farm consists of five (5) above ground storage tanks (ASTs), two of which are permanently out of service. The remaining three tanks have a combined capacity of approximately 12,096,000 gallons. The fuel oil offloading facilities (i.e., docking facilities located along Hog Island Channel) enable No. 6 fuel oil to be delivered to the site by barge.

Barrett Units 1 and 2 currently use a once-through cooling system. Cooling water is withdrawn from the western end of Hog Island Channel through two shoreline intake structures (one for each unit). Heated water is subsequently returned via a discharge canal to the western end of Barnum's Channel (which begins east of Long

<sup>10</sup>“Repowering Feasibility Study of E. F. Barrett Power Station,” National Grid, February 27, 2017



Beach Road). A sheet pile wall spanning the discharge canal is used to prevent recirculation of the heated discharge.

Additional electric generating and transmission system equipment is located north of the discharge canal. Originally, eight (8) GE Frame 5 simple-cycle peaking units were in service. However, one unit has been retired. Currently, seven (7) units are operating (Barrett CT Units 1-6 and 8). The GE peaking units were placed in service in 1970 and have a combined generating capacity of approximately 105 MW. There are also four Pratt & Whitney aero-derivative twin pack peaking units (Barrett CT Units 9-12). The Pratt & Whitney peaking units were placed in service in 1971 and have a combined generating capacity of approximately 160 MW. A one-million-gallon fuel oil tank and associated fuel truck unloading station provide back-up fuel for these peaking units.

The 127-acre Barrett property is sufficiently large to allow construction of the new generation units without impacting the operations of the existing units. LIPA's Barrett substation is located on the station's property immediately north of the discharge canal and adjacent to the combustion turbine peaking facilities.

## 2.2 CURRENT PLANT OPERATION

The Barrett steam units operate between 40 MW and 181 MW<sup>11</sup>, with a ramp rate of 2 MW/minute. The units are economically dispatched by the NYISO. The full load heat rate for Units 1 and 2 is approximately 10,500 btu/kWh while burning natural gas. Ancillary market services are provided in the form of Voltage Support Services (including testing for leading and lagging VARs), Regulation Response, and Operating Reserves. The station's five-year average capacity factor, 2012 – 2016, was 38.2%. For 2016, the net capacity factor was 44.1% with Unit 1 at 51.8% and Unit 2 at 36.4%.

To further assess the performance of the Barrett 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 B.<sup>12</sup> 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

<sup>11</sup> Nameplate capacity

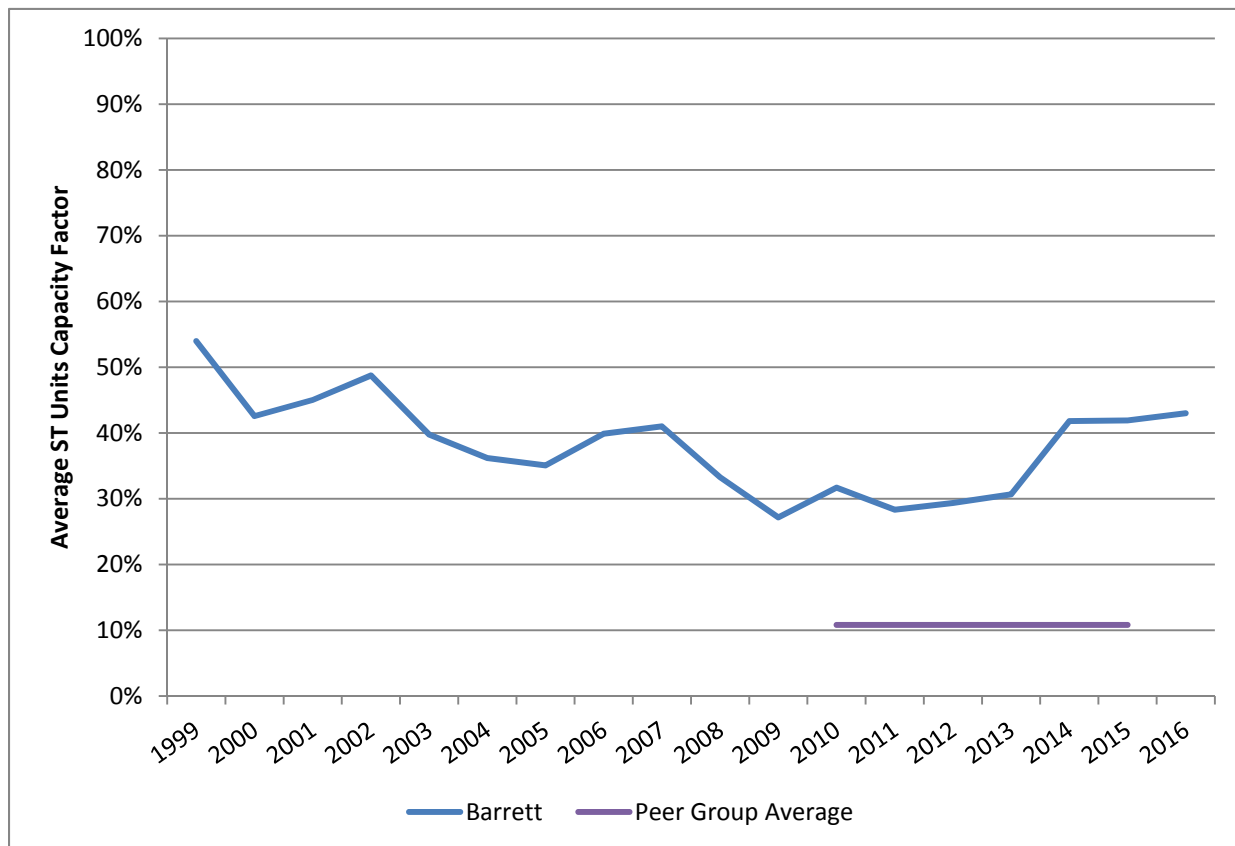
<sup>12</sup> Note that the 29 utilities and 57 units shown in Appendix B include National Grid and the four (4) Barrett and Port Jefferson steam units.



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 mean CF of the peer group was 10.8%, the mean summer EAF was 88% (higher is better), and the mean EFORD was 10.6% (lower is better).

Figure 2-1 provides the historical CF for the Barrett steam units, as well as the average of their peer group during the period 2010-2015.<sup>13</sup>

**Figure 2-1 — Steam Units Historical Capacity Factors**



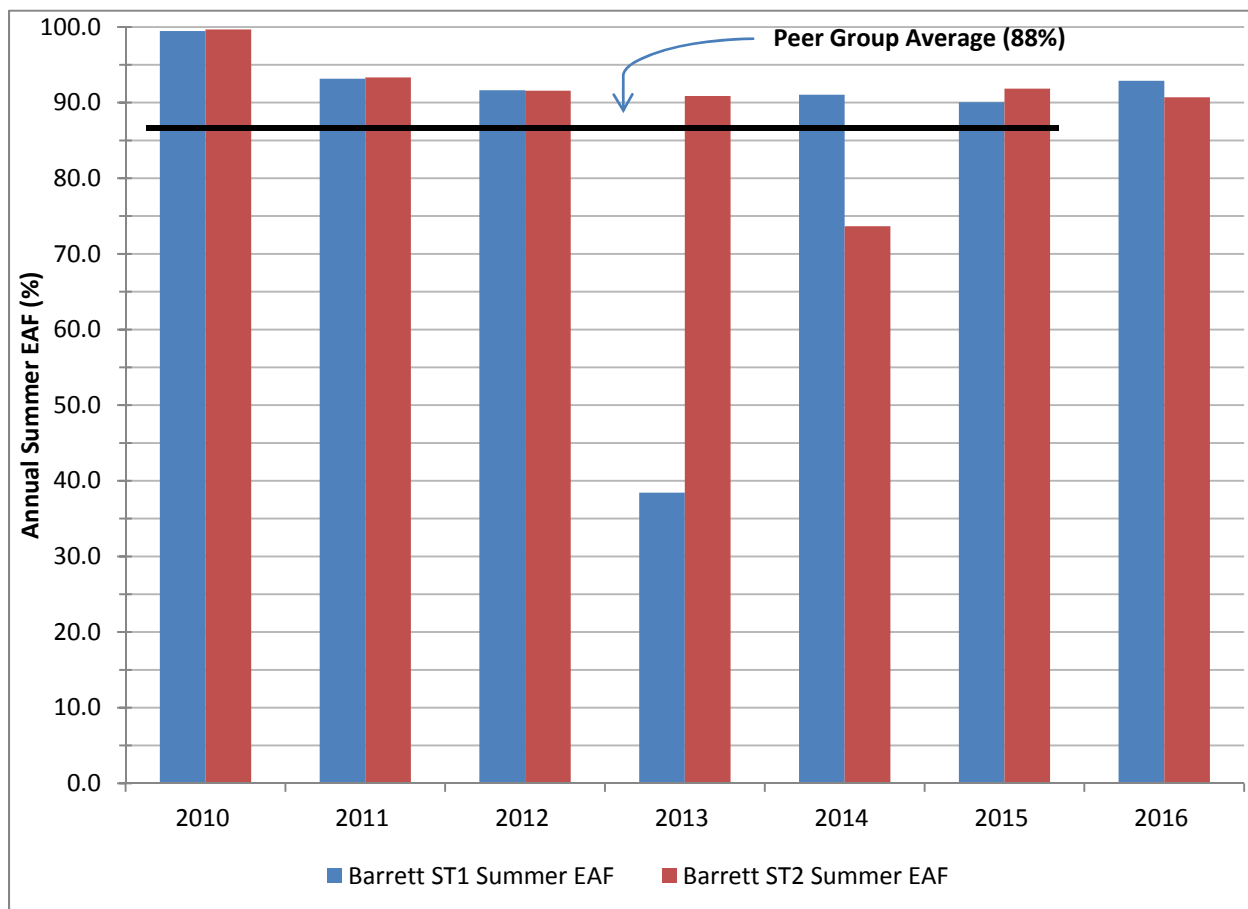
Barrett's capacity factor, while higher than the peer group, declined from the late 1990's, from a high of 54% in 1999 to below 30% in 2009, but has risen to approximately 44% in 2016 due to local load conditions.

<sup>13</sup> Peer group data for 2016 is not available.



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 subsequently shows Barrett's EAF during these three summer months.

**Figure 2-2 — Summer Equivalent Availability Factor**



Barrett's EAF performance from 2010 – 2015 for the months of June, July and August, averaged over 87%, slightly below the peer group. (Excluding Barrett Unit 1's 2013 performance, an aberrant year due to a main transformer failure, would raise Barrett's EAF to over 91%). These EAF values also are consistent with Barrett's annual average EFORD performance for the same period, a low 4.4%, which compares favorably to the peer group mean of 10.6% and supports the independent condition assessment prepared by RCMT.



Barrett Units 1 and 2 operate under various permits issued by the New York State Department of Environmental Conservation, primarily covering air emissions, water use and discharge, and storage of liquid fuel. The air permit sets limits based on pollutant and fuel type. The SO<sub>2</sub> emissions are directly proportional to the sulfur content of the residual fuel oil; the current regulatory limit is a maximum sulfur content of 0.37%. There is no Unit 1 specific emission rate limit with respect to NO<sub>x</sub>, however, there is a NO<sub>x</sub> RACT regulatory target of 0.15 lbs/MMBtu regardless of fuel. On gas, this Unit typically operates 40-50% below the target. Unit 2 does have NO<sub>x</sub> emission rate limits, based on a 24-hour average, of 0.1 lbs/MMBtu on gas and 0.2 lbs/MMBtu when combusting oil. On gas, Unit 2 normally operates about 50% below the limit. Both units have burned a very limited amount of oil, but emissions would be expected to be in the range of 0.15 lbs/MMBtu NO<sub>x</sub>. 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 a quarterly and monthly basis with any permit limit exceedances noted. The information is available to the public on various government databases.

With respect to Section 316b of the Federal Clean Water Act (i.e., aquatic protection), the Barrett steam units are operating under their current permit, which was extended under the State Administrative Procedures Act (SAPA). It was assumed for purposes of this Study that compliance with 316b by the existing Barrett steam units would be met via the installation of variable speed drives on the circulating water pumps and replacement of the traveling screens by fish friendly screens. The assumed solution (variable speed drives and fish friendly screens) for Barrett is what Grid proposed as the Best Technology Available (BTA) in permit proceedings and is similar to that accepted and implemented at Port Jefferson Northport.

## 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 Barrett units. See Appendix C 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 contract 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 \$70 million for the steam units and approximately \$18 million for the combustion turbines.



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 B shows that the Barrett Units compare favorably to similar units, further supporting the conclusions of the RCMT Assessment. Accordingly, the conclusions reached in the 2014 RCMT high level condition assessment are considered to remain valid and the Barrett plant can reasonably be expected to operate reliably at least through the termination of the PSA contract.

LAST PAGE OF SECTION 2.



### 3. REPOWERING CONFIGURATION

Grid (via Island Park) submitted a proposal to repower Barrett to LIPA in July 2014. The proposal was developed in accordance with the 2012 Power Supply Agreement (PSA) between Grid and LIPA and the terms and conditions of the PSA in place at that time. The proposal states that it reflects input from LIPA regarding the size and configuration of the proposed project.

The following repowering configuration options were provided in Island Park's proposal:

- A. Two '1x1x1' CC units (each consisting of one GE 7F.05 combustion turbine generator with one heat recovery steam generator and one steam turbine generator) based on an advanced design combustion turbine in a combined cycle configuration with an air-cooled condenser, together totaling 637 megawatts (MW); and,
- B. One '1x1x1' combined cycle unit (GE 7FA.05 as in Option A) with an air-cooled condenser and a simple cycle unit (GE 7F.05 combustion turbine), totaling 532 MW.

Both options (A) and (B) above have high thermal efficiencies, low emissions rates, and would use closed loop cooling systems. The capacity of each option would not exceed LIPA's Barrett substation exit capabilities. The proposed unit configurations would be designed for operation from 40% minimum load to 100% of nameplate rating. At Barrett, while no significant natural gas system upgrades are required, a natural gas metering station and equipment would need to be installed. A 30-day interruptible natural gas supply was assumed.

While both proposals had similar pricing characteristics, only Option A was evaluated as that configuration's proposed size is closer to the total capacity of the existing facilities being retired. The performance attributes of Option A are shown below:





**Table 3-1 — Barrett Repowering Attributes Summary**

VENDOR/CONFIGURATION (combustion turbines x steam turbines x HRSG) PERFORMANCE - GAS FIRING		GE 7F.05 2ea (1x1x1)		
Ambient Temperature: 25F		25	25	25
Load Points: 100% /75%/Min		100	75	40
Heat Input - Mbtu/hr (HHV)		4,570	3,627	2,601
Gross heat Rate- Btu/kWh (HHV)		6,572	6,761	7,608
Gross Power Output -MW		695.3	536.4	341.9
Aux Power- MW		18,564	16,981	15,315
Net Power -MW		676.8	519.4	326.5
Net Heat Rate- Btu/kWh (LHV)		6,085	6,292	7,178
Net Heat Rate - Btu/kWh (HHV)		6,752	6,982	7,965
Fuel Flow Rate (kscf./hr)		4,437	3,521	2,525
Ambient Temperature: 59F	59WC	59	59	59
Load Points: 100% /75%/Min	100	100	75	40
Heat Input - Mbtu/hr (HHV)	4,621	4,562	3,518	2,477
Gross heat Rate- Btu/kWh (HHV)	6,537	6,503	6,640	7,514
Gross Power Output -MW	706.9	701.4	529.8	329.7
Aux Power- MW	21.5	20.9	17.8	16.1
Net Power -MW	685.4	680.6	512.0	313.5
Net Heat Rate- Btu/kWh (LHV)	6,076	6,041	6,192	7,120
Net Heat Rate - Btu/kWh (HHV)	6,742	6,703	6,870	7,900
Fuel Flow Rate (kscf./hr)	4,486	4,429	3,415	2,405
Ambient Temperature: 92F	92WC	92	92	92
Load Points: 100% /75%/Min	100	100	75	44
Heat Input - Mbtu/hr (HHV)	4,490	4,383	3,296	2,487
Gross heat Rate- Btu/kWh (HHV)	6,654	6,650	6,699	7,522
Gross Power Output -MW	674.8	659.1	492.1	330.6
Aux Power- MW	22.6	21.7	19.2	18.3
Net Power -MW	652.3	637.4	472.8	312.4
Net Heat Rate- Btu/kWh (LHV)	6,204	6,198	6,283	7,176
Net Heat Rate - Btu/kWh (HHV)	6,884	6,877	6,972	7,962
Fuel Flow Rate (kscf./hr)	4,359	4,256	3,200	2,415





EMISSIONS (Gas): lbs/Mbtu (HHV) - Controlled at ISO
NOX also ppm
NH3 also ppm
CO also ppm
VOC also ppm
PM (including Ammonium Sulfates)
SO <sub>2</sub> @ 0.5gr per 100 scf
SO <sub>3</sub>
CO <sub>2</sub>

lbs/MMBtu	ppm @ 15% O <sub>2</sub>	
0.0073	2	NOX
0.0067	5	NH3
0.0044	2	CO
0.0013	1	VOC
0.0066		PM
0.0014		SO2
0.00078		SO3
116.82		CO <sub>2</sub>

PERFORMANCE - OIL FIRING
Ambient Temperatures: 25F
Load Points -100%/75%/Min
Heat Input - Mbtu/hr (HHV)
Gross Heat Rate- Btu/kWh
Gross Power Output -MW
Aux Power- MW
Net Power -MW
Net Heat Rate- Btu/kWh (LHV)
Net Heat Rate - Btu/kWh (HHV)

GE 7F.05 2ea (1x1x1)		
25	25	25
100	75	50
4,789	3,785	2,923
6,917	7,056	7,458
692.3	536.4	392.0
16.3	15.0	13.9
676.0	521.4	378.0
6,648	6,812	7,257
7,084	7,259	7,733

EMISSIONS: lbs/Mbtu (HHV) - Controlled at 25°F ambient
NOx also ppm
NH3 also ppm
CO also ppm
VOC also ppm
PM (including Ammonium Sulfates)
SO <sub>2</sub>
SO <sub>3</sub>
CO <sub>2</sub>

lbs/MMBtu	ppm @ 15% O <sub>2</sub>
0.0230	6
0.0072	5
0.0047	2
0.0036	3
0.0017	
0.0015	
0.00086	
161.15	



OPERATIONS			
Startup Time to STG Bypass Valves Closed			
Cold Start (36 - 72 hrs off)		4	hrs
Warm Start (10 -36 hrs off)		2.5	hrs
Hot Start (< 10 hrs off)		1.5	hrs

8%/min or approx 15MW/min per CT train			
Gas Operation Per Unit		Oil Operation	
Minimum Down Time (Hours)		2	hrs
Minimum Run Time (Hours)		4	hrs

LAST PAGE OF SECTION 3.



## 4. ENGINEERING & ENVIRONMENTAL ANALYSIS

Based on the current background, inputs and assumptions discussed in Section 2 above, 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 Barrett, and how they would be dispositioned under repowering (based on Option A described in Section 2.4.2).

**Table 4-1 — Disposition of Major Plant Components**

Existing Units & Components	Description & Comments	Total Current Output	Disposition	Total Output Post Repowering
ST Units 1 & 2	<u>CE Boilers</u> Tangentially fired, natural circulation boilers operating at a throttle pressure of 1825 psig, 1005°F SH, 1005°F RH	n/a	Retire & Demolish	-0-
	<u>GE STs</u> Tandem compound reheat triple flow LP stage steam turbines and generators	390 MW	Retire & Demolish	-0-
CT Units 1-6, 8	<u>GE CTs</u> Frame 5 Simple-cycle peaking units	105 MW	Retire & Demolis	-0-
CT Units 9-10	<u>Pratt &amp; Whitney CTs</u> Aero-derivative twin pack peaking units	80 MW	Retire & Demolish	-0-



Existing Units & Components	Description & Comments	Total Current Output	Disposition	Total Output Post Repowering
CT Units 11-12	<u>Pratt &amp; Whitney CTs</u> Aero-derivative twin pack peaking units	81 MW	No Change <sup>14</sup>	81 MW
2 – CC Units	2 – 1x1x1 CC units (1 unit = 1 CT, 1 HRSG, & 1 ST)	-0-	New	637 MW
BOP Equipment	Various	n/a	Reuse or retire	n/a
Cooling Water System	Once through; withdraw & discharge into Hemstead Bay	n/a	Retire	n/a
	ACC: Closed loop	n/a	New	n/a
Interconnection Substation	Various	656 MW	Reuse	718 MW
<b>Total Plant Output: Current &amp; Repowered</b>		<b>656 MW</b>		<b>718 MW</b>

The combined cycle units would operate on natural gas and have ultra-low sulfur distillate (ULSD) fuel backup, with an onsite five-day storage capability. They would have advanced Dry Low nitrogen oxide (NOx) combustors for natural gas firing and water injection for NOx control on distillate (ULSD) fuel. A selective catalytic reduction system (SCR) and any other necessary emission controls would be included in the design.

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 detailed design. For example, the exact number and specific CT units to remain as part of the repowered station may evolve during the design process. These changes are an expected part of any design process, and do not materially impact the overall results of this Study.

<sup>14</sup> Note that Units 11 & 12 are designated for retirement on a preliminary basis only. Two of the four Pratt & Whitney CTs will be retired, while two will remain in service; specifically, which of the four CT units to be retired does not impact this Study.



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

#### **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 (i.e., the proposed CC units) 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 (NO<sub>x</sub>, SO<sub>2</sub>, CO, CO<sub>2</sub>, PM, and VOC). These attributes have been used in the transmission, dispatch, and economic analytical models for this Study.

#### **4.1.3 Fuel Supply, Delivery and Storage**

Natural gas will serve as the primary fuel for the proposed repowered facility. The proposed facility will continue to use Grid's (i.e., KeySpan Energy Delivery Long Island, or KEDLI) existing natural gas transmission system for the delivery of natural gas to the site. KEDLI currently supplies natural gas to the existing steam boilers (Units 1 and 2), as well as to the existing peaking units at Barrett. Natural gas is delivered through the Transco pipeline that enters the KEDLI system at Long Beach. The KEDLI 30-inch diameter mainline gas supply enters the site from Long Beach Road to the east of the LIRR property. The existing natural gas supply to the site would be adequate to satisfy the needs of either repowering configuration option under a 30-day interruptible contract agreement. No new offsite natural gas infrastructure or offsite infrastructure improvements will be required to serve the proposed facilities. However, a natural gas metering station and equipment will be required.

Ultra-low sulfur distillate (ULSD) will serve as a backup fuel. Approximately five (5) days of onsite fuel oil storage capacity will be provided for the proposed facility. ULSD will be stored in a new above ground storage tank. Associated truck unloading facilities, including safety systems, transfer piping, and feed systems will also be installed. In addition, the existing marine unloading facilities at Barrett will be available to receive and unload fuel oil deliveries via barge. Consistent with New York State and County requirements, the fuel oil storage tanks would have secondary containment capable of containing 100 percent of the tank contents plus sufficient freeboard for 8-inches of precipitation.



ULSD will be delivered to the facility via tanker truck or barge. Tanker truck deliveries will be unloaded at a tank truck unloading area specifically designed for this purpose. Based on a preliminary design, the facility will have the capability to unload two (2) fuel oil tank trucks simultaneously. It is anticipated that each tanker truck can be unloaded in approximately one hour. Barge deliveries will be unloaded at the existing Barrett barge unloading wharf, which is currently used for the delivery of No. 6 fuel oil for existing Units 1 and 2.

Based on the above discussion regarding existing facilities in place to accept fuel oil, there are no current plans to deliver ULSD to the site via pipeline, as ULSD only represents a back-up fuel for the facilities and not a primary fuel.

#### **4.1.4 Electric Interconnection**

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

## **4.2 TRANSMISSION SYSTEM**

The proposed Barrett repowering project results in a total capacity of 718 MWs at the site. The project consists of two new 1x1x1 combined cycle units plus the retention of two existing simple cycle combustion turbines already in situ. The project, from a transmission system perspective, was examined against two relevant criteria; site exit capability, and the North American Electric Reliability Corporation's (NERC's) transmission planning standards.

### **4.2.1 Site Exit Limitation**

Site exit capability is the maximum amount of energy that can be exported from the Barrett site after the loss of one transmission circuit. The exit limitation is determined by the transmission capability of circuits, transformers and load on the Barrett 138kV bus. The normal rated capability of the circuits and transformers coming out of Barrett sum up to ~770 MW. If load served from the 138 kV bus, as assumed in the 2016 Summer Operating Study, is included, the exit capacity is increased ~58 MW to a total of 828 MW. This raw capability, however, cannot be accomplished due to the differing impedance and ratings of the circuits and transformers. The limiting contingency is the loss of the Barrett to Valley Stream 138 kV circuit 1 (138-291), which will increase the loading on the Barrett to Valley Stream 138 kV circuit 2 (138-292). To avoid an overload on 138-292, it is necessary to limit the capacity of the repowered project to 710 MWs. Since the



configuration studied totaled 718 MWs, it may be necessary to retain one existing 15 MW combustion turbine in lieu of a 40 MW CT limit. This would avoid the need for transmission upgrades and have negligible financial impact.

#### **4.2.2 NERC Planning Standard**

In addition to an exit limitation, the proposed project was examined from the perspective of adherence to NERC planning standards. The transmission system in the Barrett area becomes limited when considering the loss of two single Bulk Electric System (BES) elements in an N-1-1 scenario (i.e., a NERC contingency analysis standard). An N-1-1 scenario considers the loss of a single BES element followed by a period of system adjustments (to bring the system back to normal) and then the loss of another BES element. The BES system is secured for system dispatch between contingencies, as system adjustments are made for maintaining transmission security. The operating criteria for transmission security require that following the occurrence of a contingency (N-1-0) that the system is secured to normal to prepare for the next contingency. Examples of the system adjustments implemented to return to normal rating include generation re-dispatch, dispatching quick-start CT's (operating reserve), Phase Angle Regulator (PAR) control, high voltage, direct current (HVDC) cable control, switched shunts, and tap changer control.

Currently, there are three limiting N-1-1 contingency pairs in the Barrett area. The first is the loss of the first Barrett to Valley Stream circuit (138-291) followed by the loss of the second Barrett to Valley Stream circuit (138-292), which will overload the East Garden City to Valley Stream 138 kV circuit (138-262). This scenario is the most limiting to the region and requires a second East Garden City to Valley Stream circuit to alleviate the violation. The second scenario is the situation when there are two large Barrett units and there is the potential for the loss of one unit, followed by the other, resulting in the overloading of the East Garden City to Valley Stream 138 kV circuit. Finally, there is the scenario of the loss of a Barrett unit followed by the loss of the Freeport to Newbridge 138 kV circuit (138-461). After the loss of the unit, the system would be dispatched to import more power to the Barrett load area. Moreover, the only path available is the East Garden City to Valley Stream 138 kV circuit, which could be overloaded depending on the generation available at Barrett and would limit the size of the repowered units under an N-1-1 analysis.

Under the last scenario, the maximum allowable size per unit was previously calculated to be 285 MW due to N-1-1 system limitations. With this assumption, the loss of a single 285 MW unit followed by the loss of Freeport to Newbridge 138kV circuit would require more than 400 MW to be online at Barrett 138kV bus after the loss of the unit. Since the size of one of the proposed combined cycle units is ~35 MW larger (319 MWs – 285





MWs) than the previously assumed size, it is expected that the loss of one of the new units would require more than 400 MW to remain on line. Under the proposed plan, after the loss of 319 MW, only 399 MW (i.e., 718 MWs total site capacity minus 319 MWs for one combined cycle unit) of generation would be available on the Barrett 138kV bus. The installation of a second East Garden City to Valley Stream line, planned to be in service by 2021, addresses the N-1-1 system limitations in the area and would increase the maximum allowable size per unit at Barrett such that the proposed units will not need to be resized or cause the need for transmission upgrades.

### 4.2.3 Conclusion

After the completion of earlier studies, a few aspects of the transmission system have changed, the main change resulting from the revised ratings for the BES system (100 kV and above). Most of the rating changes resulted in decreased ratings for circuits in the area. It is expected that the exit limitation from Barrett will decrease slightly due to the decreased ratings on 138-291 and 138-292 and, under current conditions, the revised exit limitation would – marginally - not accommodate the 718 MW of the proposed generation. However, the proposed project could be easily reconfigured to address this limitation at de minimis cost with no transmission upgrades. Similarly, the installation of the second EGC to Valley Stream 138 kV circuit is expected to address the N-1-1 limitations in the area and will be revisited with updated system configuration.

In sum, there are no transmission system upgrade expenditures associated with the proposed Barrett repowering.

## 4.3 ENVIRONMENTAL CONSIDERATIONS

### 4.3.1 Permitting

The Article 10 permitting process has already been initiated through the application for The Island Park Energy Center – A Repowering of E.F. Barrett Power Station (Island Park). Pursuant to the Article 10 requirements, draft and final Public Involvement Programs, the Preliminary Scoping Statement (PSS), and the response to public comments on the PSS have already been submitted. The prehearing conference before the presiding and associate hearing examiners has also taken place, and PSS/study stipulation intervenor funds have been allocated by the examiners. Draft study stipulations have been circulated to the active parties. Several meetings and revised draft stipulation submissions have also been completed.

Permitting efforts will be continued under Article 10 by revising the draft study stipulations that have been previously circulated to the parties. The anticipated revisions to the stipulations are intended to reflect the





smaller facilities now being proposed. Major revisions are not expected to the proposed studies that were the subject of the original draft stipulations since potential environmental impacts should be lower in most if not all respects. Consequently, revisions to the existing draft Article 10 application that has previously been prepared for Island Park should not be extensive and can be completed relatively expeditiously.

Once the Application is filed, the Siting Board is allotted up to sixty days to determine that the application complies with the statutory filing requirements. Assuming the Siting Board takes the full sixty days to issue its compliance determination (which period would also include any responses by Grid to requests for additional information from the Siting Board Staff), the six-month review period provided in Article 10 for repowering facilities would ensue. Article 10 requires the Siting Board to make its decision on an application for a proposed repowering within this period. Per the Island Park proposal, Grid would submit and secure approval of the initial phases of the facility's compliance filing within this six-month period, and could begin construction of the facility immediately by starting site preparation activities upon receipt of the Article 10 certificate.

Table 4-2 below provides a summary of anticipated environmental permits, approvals and agency consultations required for the repowering.

**Table 4-2 — List of Permits and Approvals**

Agency	Department	Permit/Approval	Agency Action
State	New York State Board on Electric Generation Siting and the Environment	Certificate of Environmental Compatibility and Public Need	Required for commencement of construction activities.
Federal	US Army Corps of Engineers (USACE)	Section 10 of the Rivers and Harbors Act of 1899/ Section 404 Clean Water Act	Required for structures or work in navigable waters within or under navigable waters of the US (i.e., existing discharge canal). Level of permitting (IP or NWP) will be based on impacts resulting from specific construction activities.
Federal	Federal Aviation Administration (FAA)	Determination of No Hazard to Air Navigation	Required pursuant to FAA Regulations, Part 77- Objects Affecting Navigable Airspace for construction cranes or other elevated structures exceeding 200 feet or to be used within proximity to an airport or heliport.



# Repowering Feasibility Study

4-8  
Engineering & Environmental Analysis  
Draft

Agency	Department	Permit/Approval	Agency Action
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 will result in a disturbance of greater than one acre or the discharge of treated dewatering effluents. Notification is also required for the termination of permitted process wastewater or stormwater discharges.
State	NYSDEC	Article 15 - Use and Protection of Waters	Required for all work below mean high water line on protected streams.
State	NYSDEC	Tidal Wetlands Permit	Required for any work within coastal wetlands and their associated buffer.
State	NYSDEC or New York State Board on Electric Generation Siting and the Environment	Water Quality Certification	In accordance with Section 401 of the Clean Water Act, applicants for a Federal license or permit for activities that may result in a discharge into waters of the United States must obtain a water quality certification from the state agency charged with water pollution control indicating that the proposed activity will not violate NY State water quality standards.
State	NYSDEC	Threatened and Endangered Species Inventory Review	Consultation letter must be sent to the New York Natural Heritage Program (NYNHP), to determine if the project will impact any protected plant or animal species habitat. "Determination of No Effect" required to support issuance of NYSDEC permits.
State	NYSDEC	Major Oil Storage Facility Permit	From NYSDEC DER-11 - <a href="#">Procedures for Licensing Onshore Major Oil Storage Facilities</a> , APPENDIX B.



Agency	Department	Permit/Approval	Agency Action
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 Article 10 process.

#### 4.3.2 Permitting Studies

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



Detailed draft studies had been prepared in 2013-2015 for the applicable exhibits listed above to identify and assess any potential impacts resulting from the larger repowering configuration originally proposed in the early 2000's than the smaller two repowering configurations now being evaluated in this Study. As stated above, only minor revisions should be required to the studies as the two new repowering options will have fewer potential impacts.

The project will also require air and water permits issued by the New York State Department of Environmental Conservation (NYSDEC). This will 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 will also be required. These permits are issued, together with the Article 10 certificate, within the Article 10 six-month deadline. Finally, a wetland delineation of the entire 127-acre property was previously performed.

#### **4.3.3 Repowering Plant Air Emissions and Water Issues**

Barrett 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 units lower CO<sub>2</sub> emission rates (lbs/MWh) by approximately 35% and NO<sub>x</sub> 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 Barrett 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 Barrett.



## **4.4 CONSTRUCTABILITY**

### **4.4.1 Equipment Delivery**

Trucks would be utilized as the primary source to deliver construction materials, equipment, and supplies for the repowering project. The trucks are not anticipated to have a significant impact on the capacity of traffic conditions in the area. Delivery of any large equipment would be coordinated with local officials and Nassau County. During construction, it is estimated that there would be an average of twenty truck deliveries per day. However, this does not include deliveries of cut and fill material. The fill delivery schedule will be dependent upon the commercial activity at the time of construction. Efforts would be made to limit the number of trucks during peak commuting hours.

The hauling of the cut and fill materials to and from the project site would occur in accordance with the substantive provisions of the applicable local laws and ordinances during the construction period. These vehicles can range in weights from approximately 20 tons to 55 tons, depending upon the type and amount of materials that they are carrying. Any required permits for truck use would be obtained. The utilization of barges to transport a portion of the cut and fill would also be a consideration.

Most roads in the area are wide and thus can support over-size loads. All over-size load deliveries would be coordinated with the appropriate agencies.

### **4.4.2 Laydown Space**

The repowering project site can be designed to optimize construction worker parking and trailers onsite as well as provide areas for construction material laydown. Throughout the different phases of construction, it is anticipated that most workers would be able to use the existing property for parking needs. Local parking areas for the workforce could be supplemented as needed. Additionally, areas for offsite laydown could also be procured as necessary to meet construction needs. Local parcels immediately surrounding Barrett are available for potential offsite laydown and parking during construction. Locations would be identified during the Article 10 Certificate process and selected due to their proximity to Barrett, due to vacant land available for parking and/or laydown purposes and due to existing industrial and/or commercial lands uses of the parcels.



#### 4.4.3 Impact on Existing Facilities from Construction Activities

Adequate land area is available on the 127-acre Barrett property to construct the selected repowering configuration while maintaining full operation of the existing facilities. Once the proposed facility is fully commissioned, the decommissioning and demolition of existing facilities would commence.

### 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, etc. The problem at the site due to that storm was flooding of the LIPA-owned switchyard that connects the plant to the power grid. LIPA subsequently undertook the investment necessary to elevate the substation equipment to prevent a recurrence.

To harden the new repowered plant, a site-specific flood analysis was performed to determine the flood zone and limits of storm surge at the Project site. Based on this analysis, the recommended flood mitigation strategy is to raise site grades and/or critical equipment such that it is 2 feet higher than the projected 500-year return period flood elevation and design the facility to protect against Category 3 hurricane winds. The 500-year flood elevation is anticipated to occur or be exceeded, on average, once every 500 years. Category 3 hurricane winds range from 111 miles per hour (mph) to 130 mph.

The site-specific study's 100-year return period stillwater flood elevation is close to the 2009 FEMA 100-year stillwater elevation. The site-specific study predicts a higher flood elevation than FEMA for the 500-year return period with the inclusion of Irene and Sandy and through use of synthetic hurricanes to add additional, more intense hurricanes to the analysis database.

The stillwater elevation associated with the updated 500-year return period storm has been determined to be elevation 14 feet (NAVD88). To protect the new generation equipment against the 500-year return period storm, the design flood elevation for a new facility would need to be elevation 16.0 feet (NAVD88), two feet above the 500-year return period storm, primarily through placement of fill in proposed development areas. Perimeter retaining walls would be utilized, where necessary, for slope stabilization. This compares to the elevation of the current plant of 12 feet.





## 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”) all or any portion<sup>15</sup> of the Barrett generating unit capacity at the site, which it is obligated to purchase from GENCO (i.e., National Grid or Grid). The exercise of the Ramp Down is subject to the following conditions:

- Prior written notice: LIPA must provide 2-years notice for steam units and a 1-year notice for all other units.
- 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 operating and maintenance expenses (both allocated and direct) and 12 months of operating and maintenance expenses in the case of non-steam units, less
  - The “notional” 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 will be reduced accordingly. Grid, upon receipt of the Ramp Down notice must, within 90 days, advise LIPA whether Grid will either continue to operate the ramped down 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 Barrett 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.

<sup>15</sup> Ramp Down of the Barrett Steam Units 1 and 2 must occur as a “block”. Ramp Down of any or all other generating units at the site may occur individually or collectively.



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 a separate section of this Report.

## **5.2 ECONOMIC ANALYSIS**

### **5.2.1 Cost and Emission Impacts**

The costs and benefits of a Barrett Repowering are reflected in the results of the Production Costs and Financial Model runs.<sup>16</sup> 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 Option A of the Barrett repowering proposal, which includes installation of two 1x1x1 GE 7FA gas fired combined cycle units (*i.e.*, a total of 637 MW). This option assumes that construction of the “new” (repowered) units would occur on the Barrett site while the existing units continued to operate. The commercial operation date (COD) of the “new” (repowered) units would be January 1, 2021 at which time the following existing units at Barrett would be shut down and subsequently demolished:

- Steam units 1 & 2

---

<sup>16</sup> The key tools used to assess the production cost, emissions and capacity impacts are described in Appendix D - Production Cost Methodology, and Appendix E - Market Forecasting Methodology.





- GE combustion turbines (CT) 1 – 6, and 8 (CT 7 is retired)
- Two Pratt & Whitney CT units

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

- A 30-year term with a buyout option in year 20, or a 40-year term with a buyout option in year 30
- A constant (flat) annual capacity payment, or escalating capacity payments
- Fixed O&M payment with a fixed annual escalation
- Variable major maintenance and O&M \$/MWH charges
- PILOT's 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 Barrett units, such payments including the:

- Net book value of the ramped down units as of January 1, 2021, less the applicable Appendix G (of the PSA) discount, less<sup>17</sup> the amount in the notional tracking account, and
- Costs associated with demolition and site remediation

LIPA payments under the PSA would be reduced to reflect the “removal” of the ramped down Barrett 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. Infrastructure improvements, both gas and electric, were assumed to not be required as the repowered units are essentially the same size (MW) as the units being replaced.

### 5.2.3 Results

The impact on LIPA's annual revenue requirements associated with the Barrett repowering proposal described above was measured as the difference between two Financial Model runs covering a 20-year Study period 2016 – 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

---

<sup>17</sup> The credit from the notional tracking account would be the lesser of the Ramp Down payment or the amount in the tracking account.



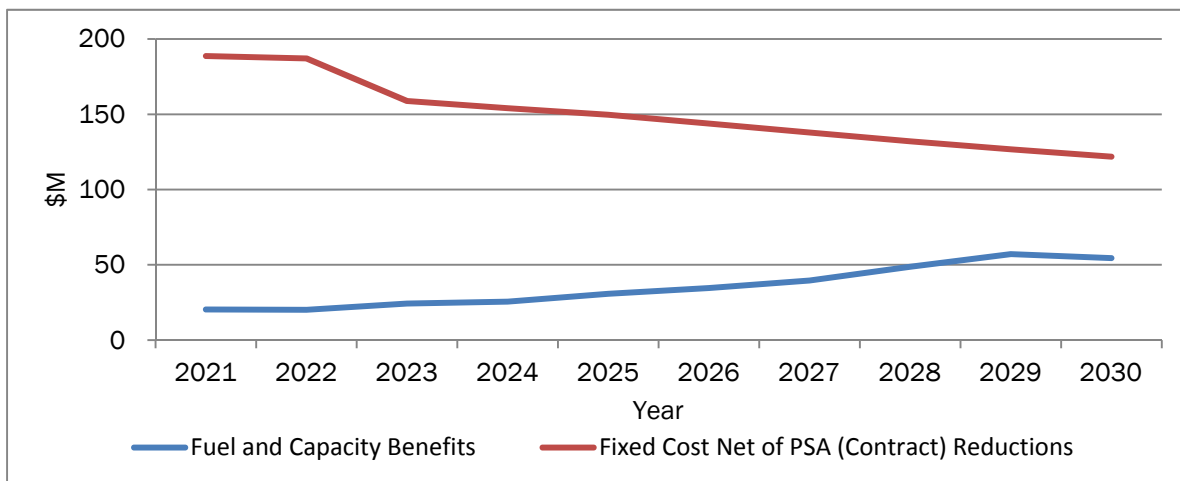
goal of 400 MW of renewable generation; the cables (Neptune and Cross Sound Cable) remaining in-service; and, the satisfaction of local and statewide reliability obligations.<sup>18</sup>

- The “reference” case but for the assumed Barrett 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 PPA with escalating pricing. A 40-year term with escalating pricing has the advantage of lower front end payments similar to a “teaser” mortgage but is hindered by high back end payments and higher total costs. Additionally, it is important to note that the Authority (LIPA) has never entered into a 40-year PPA and believes that such a contract tenor 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 into have maximum terms of 20-years or less, not 30-year PPAs. A 40-year term is also beyond the tenor the Authority uses for its own borrowing and obligations.

Production cost modeling for the Integrated Resource Plan was the basis for the Barrett repowering evaluation and the study period for that effort was the 20-year period 2016 – 2035, which, assuming a 30-year term, is 16 years short of the proposed 2051 termination for the Barrett PPA.

**Figure 5-1 — Increase in Annual Costs Associated with Barrett Repowering**



<sup>18</sup> Satisfying the LI Locational Capacity Requirement (LCR) and the Statewide Installed Reserve Margin (IRM)



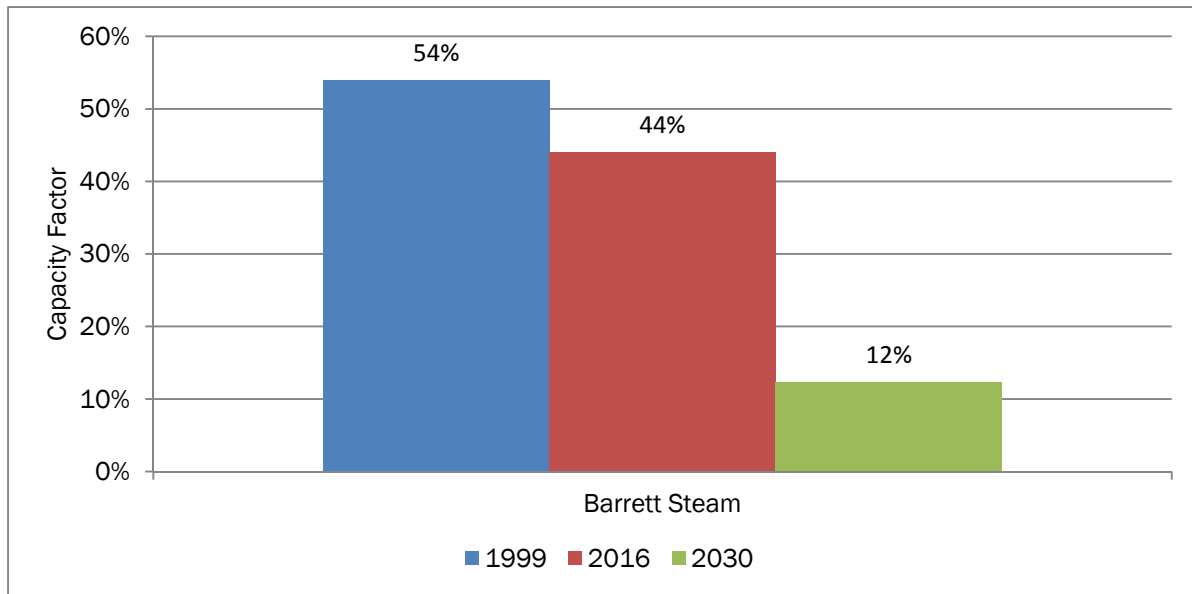
As shown in the results reflected in Figure 5-1, the Barrett repowering proposal results in increases in LIPA's costs in each year for the period depicted. In other words, the reduction in production costs (fuel and purchased power) attributable to the more thermally efficient repowered units, along with the decrease in the PSA annual Capacity Charge resulting from the retirement of the existing Barrett units, is not sufficient to offset the higher PPA fixed costs associated with the repowered units. As measured over the first 10 years (2021 – 2030) of the Barrett PPA the total additional cost to LIPA's customers is \$1.145 billion and over the course of the Study period (thru 2035) the total additional costs to LIPA's customers is \$1.302 billion.

The Barrett repowering proposal will result in increases in residential customers' bills. As measured over the first 10 years (2021 – 2030) of the Barrett PPA, the total additional cost to an average residential customer is \$514 and over the course of the Study period (thru 2035) the additional costs is \$577.

The repowered project results in an approximate 4% decrease in LIPA's annual CO<sub>2</sub> emissions footprint system-wide, i.e., the reduction in emissions associated with satisfying LIPA's total annual energy requirements, assuming Barrett 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 existing Barrett steam units for three distinct years. As shown, the annual capacity factor declined from 54% in 1999 to 44% in 2016 and is projected to decline to 12% by 2030.



**Figure 5-2 — Barrett Capacity Factor Trend**



As noted previously, capacity factor is a measure of a generating unit's energy output and, therefore total emissions, since emissions are directly related to energy output. Consequently, even in the absence of repowering, emissions at Barrett 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 Barrett 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 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 GENCO (Grid) notifies LIPA that it, pursuant to Section 10.2.2, will shut down and mothball or demolish the generating facility as of the effective date of the ramp down LIPA has the right to purchase the generating facility including the related site.<sup>19</sup> 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 GENCO, to repower or construct new generation on the site. However, regarding the repowering of the steam units (*e.g.* Barrett Units 1 & 2), 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 GENCO to ramp down and repower the generating facility and GENCO would be responsible for doing so. For each repowering that LIPA elects to exercise, LIPA and GENCO would enter into a separate PPA wherein GENCO 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, provided such lease or purchase does not materially interfere with either the physical operation of any generating facility or environmental compliance. In the event of interference LIPA must provide compensation. The lease or purchase price will include the fair market value at the time of lease or purchase as determined by a jointly selected independent real estate appraiser. Of note, the Barrett site is believed to have sufficient available land to develop new generation on the site separate from the existing units. There may also exist parcels of land adjacent to the Barrett site upon which new generation could be economically and efficiently sited to make use of existing natural gas and electrical interconnection facilities independent of LIPA's rights under the PSA or Schedule F.

LAST PAGE OF SECTION 5

<sup>19</sup> 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.



## 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 Barrett, 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 fully understood. A subjective 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 excepting 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 Barrett 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.

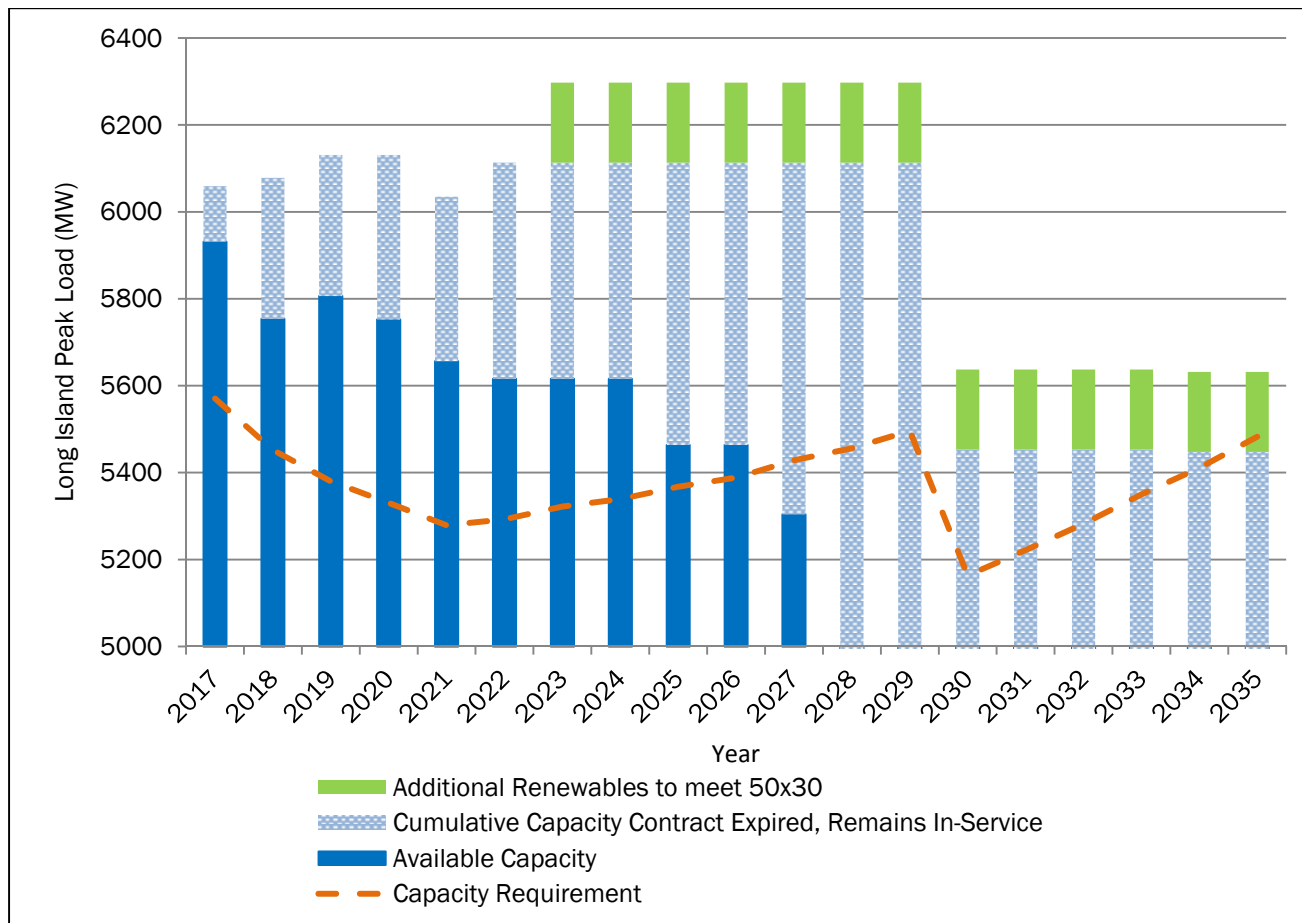




### 6.3 EXISTING CONTRACTS, & NEED FOR FLEXIBILITY

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**



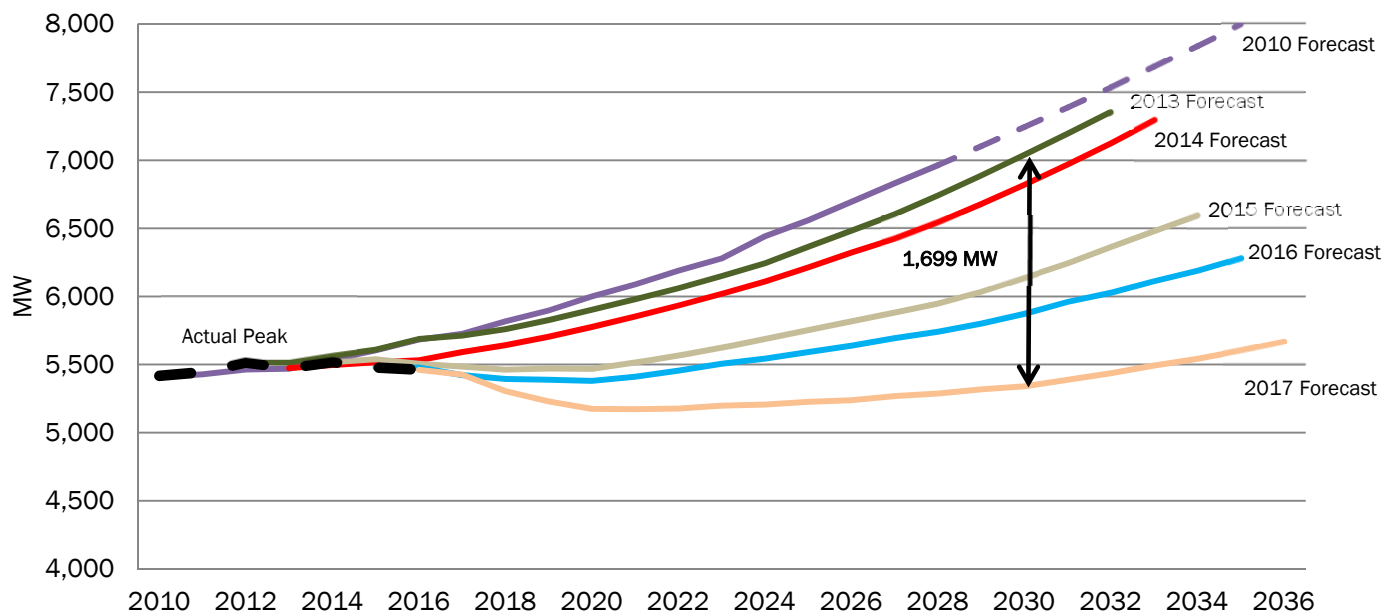
### 6.4 PEAK LOAD FORECASTS

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 two and one-half 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 Barrett.

LAST PAGE OF SECTION 6.



## 7. COMMUNITY IMPACTS

### 7.1 JOBS

Construction of the repowered unit would likely create nearly 400 jobs per month during peak construction months. The overall duration of the construct period is expected to range between 2-1/2 to 3 years, with the peak period occurring during the second and third quarter of the second year. Demolition of the existing facilities is not required until after repowering and may take from one to two years, but is expected to require less effort than construction of the new facility.

The staffing level for the repowered station will be less than current staffing. Barrett currently requires approximately 60 on-site personnel. After repowering, the station will require approximately 25-30 personnel. Plus, the mix of trades may vary. Due to the smaller number of CTs that will remain in operation, the number of jobs required for major maintenance evolutions is also expected to decrease depending on the amount of change in the overall numbered of fired hours of the more efficient units. Overall, the most significant impact on jobs is expected during the relatively short construction period.

There also would 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. LIPA's 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 — Disproportionate Legacy Property Taxes**

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 Barrett, and other legacy plants, is stark and informative. The repowering proposal for Barrett represents a modest reduction in the proposed tax levy, i.e., from \$36 million to \$29 million, which remains approximately 50% more than LIPA could pay for new generation of a similar size installed in other parts of 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 Barrett power plant. The repowering project is based on replacing the two existing steam units, seven operating GE CTs, and two of the four Pratt & Whitney CTs with two 1x1x1 combined cycle units, each unit consisting of one GE 7F.05 CT, one HRSG, and one steam turbine, as well as keeping two of the existing four Pratt & Whitney CTs in operation.

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

- The existing Barrett plant can be expected to continue operating reliably, at a minimum, through the end of the PSA.
- Grid, through Island Park, has proposed a repowered configuration that has certain environmental benefits and better operational characteristics compared to the existing Barrett 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 Barrett units, are not sufficient to offset the higher PPA fixed costs associated with the repowered units.
  - The Barrett repowering project will result in increases in customers' bills. As measured over the first 10 years (2021-2030) that the repowered unit is in service, the total additional cost to LIPA's customers is \$1.145 billion and over the course of the Study period (thru 2035) the total costs to LIPA's customers is \$1.302 billion. For an average residential customer, the total additional cost over the first 10 years is \$514.
- Because this Study exclusively evaluated repowering the Barrett facility (i.e., it did not compare a repowered Barrett 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 Barrett 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 Barrett'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





<b>Term</b>	<b>Definition or Clarification</b>
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 kW
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
NYS DPS	New York Department of Public Service
NYISO	The New York Independent System Operator (NYISO)



<b>Term</b>	<b>Definition or Clarification</b>
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.



## Repowering Feasibility Study

---

### Appendix A. Previous Repowering and Referenced Studies

---



## PREVIOUS REPOWERING AND REFERENCED STUDIES

The following timeline summarizes previous work regarding repowering Barrett:

- **2003** “Repowering Study Phase II, E.F. Barrett Unit 1,” prepared for KeySpan Energy Development Corp. by Lockwood Greene E&C. This study provided a detailed technical assessment and capital cost estimate to repower E.F. Barrett Unit 1 with “F” class combustion turbines in a 2x1 configuration using the existing steam turbine generator and auxiliary systems to the maximum practical extent. A second option, based on a similar 2x1 configuration but with a new steam turbine generator, was also included.
- **2003** “Evaluation of the KeySpan PSA Generating Units Prepared for Long Island Power Authority,” John H. Koubek, et al., Department of Public Service, October 2003.
- **2007** “Purchase and Repowering Options: EF Barrett, Far Rockaway, Shoreham and Wading River Generating Facilities”, May 2007
- **2009** Based on the 2006 Integrated Resource Plan and the 2007 study referenced above, determined that repowering Barrett was technically viable.
- **2014** RCMT Condition Assessment concluded that the PSA generating units can continue to operate reliably through 2028 and beyond.



## Repowering Feasibility Study

---

### Appendix B. Benchmarking

---

**CONFIDENTIAL**



## Repowering Feasibility Study

---

### **Appendix B. Benchmarking – Annual**

---

**Sargent&Lundy**  
**National Grid**

**Report # 14**

**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

Page: 1

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 Occurences	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

Page: 1

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&amp;Lundy

GADS Report (Based on IEEE Standard 762)

Printed: 4/04/2017

Page: 1

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

**Units Included in Study # 14**

Sargent&amp;Lundy

GADS Report (Based on IEEE Standard 762)

Printed: 4/04/2017  
Page: 2

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

**Units Included in Study # 14**

Sargent&amp;Lundy

GADS Report (Based on IEEE Standard 762)

Printed: 4/04/2017

Page: 3

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

---

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&amp;Lundy

GADS Report (Based on IEEE Standard 762)

Report No.: 15

Printed: 4/04/2017

Page: 1

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 Occurences	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

Page: 1

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&amp;Lundy

GADS Report (Based on IEEE Standard 762)

Printed: 4/04/2017

Page: 1

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

**Units Included in Study # 15**

Sargent&amp;Lundy

GADS Report (Based on IEEE Standard 762)

Printed: 4/04/2017

Page: 2

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&amp;Lundy

GADS Report (Based on IEEE Standard 762)

Printed: 4/04/2017  
Page: 3

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 C. RCMT Condition Assessment Report (Redacted)

---

Redacted Version

**PSEG**

**Long Island**

**CONDITION ASSESSMENT**

**OF**

**NATIONAL GRID**

**ELECTRIC GENERATION ASSETS**



**TECHNICAL REPORT**

**December 30, 2014, Revision 1**



2500 McClellan Avenue  
Pennsauken, NJ 08109

## TABLE OF CONTENTS

1.0	EXECUTIVE SUMMARY .....	1
1.1.	Introduction .....	1
1.2.	Summary of Findings.....	1
2.0	ASSESSMENT OF ELECTRIC GENERATION ASSETS.....	3
2.1.	National Grid Management Programs & Controls.....	3
2.2.	Steam Generation Facilities .....	8
2.2.1	Northport Power Station .....	8
2.2.2	E.F. Barrett Power Station.....	10
2.2.3	Port Jefferson Power Station .....	12
3.0	Combustion Turbine Generation Facilities .....	15
3.1.	General Overview .....	15
3.2.	System Performance.....	16
3.3.	Capital Improvements.....	18
3.4.	Gas Turbine 5000 Start Rotor Issue .....	19

## APPENDICES

1.1	National Grid Electric Generation Scorecards (Steam & CT)	21 Pages
1.2	Northport P.S. Units 1-4, Major Boiler Modification History Description and Listing Rev. 19	15 Pages
1.3	List of Documentation Provided by National Grid	4 Pages
1.4	PSA Units Summer Availability Factor / Annual DMNC Weighted EFORD / PSA CT Unit Startup Reliability	1 Page



## **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 2<sup>nd</sup> 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 1<sup>st</sup> 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]

[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 evaluation 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 leveled 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 1<sup>st</sup> through August 31<sup>st</sup>), 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 of [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 under [REDACTED] as they occur during the year.

Non-repetitive projects in the five (5) year plan include projects such as Remote Terminal Unit (RTU) upgrades (at East Hampton, E.F. Barrett, Glenwood, Holtsville, South Hampton, Southold, W. Babylon and Wading River), Disturbance Monitoring Equipment installations (E.F. Barrett, Holtsville and Shoreham), exhaust plenum and elbow replacements (E.F. Barrett and Holtsville), generator rotating cooling fan replacements (E.F. Barrett), exhaust stack

replacements (E.F. Barrett, Holtsville and Wading River), CO2 fire protection system replacements (Wading River), turbine casing replacements (Wading River), and inlet duct replacement (Holtsville and W. Babylon). Review of the overall Capital Improvement Projects program shows it as robust and well planned out. The program will assist greatly in the continued operation of these units for the next five (5) years.

### 3.4. Gas Turbine 5000 Start Rotor Issue

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

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

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

National Grid has been very pro-active to comply with the recommendations of TIL 1576. Prior to the latest revision lifting the hard start limit, National Grid had replaced the original turbine rotors in the Southold and South Hampton units (Southold with a purchased used rotor and South Hampton with the rotor removed from EFT Unit No. 7). Additionally, National Grid completed extensive research of all historical operating logs and data to accurately determine the true factored starts of each unit. These results are shown in Appendix No. 1.3, Item 13. Based on this accurate verified data and the average projected annual number of starts

per unit, there are two (2) units which will reach the 5,000 factored start limit during the 2015-2019 time period. These are E.F. Barrett Unit Nos. 6 and 8 (Unit No. 2 is projected to be due in 2020). National Grid plans to perform all recommended inspections at the advised limits as they become due and, based on prior National Grid and industry experience to date, anticipates rotor life to be extended. The probability to not extend the life of these units is extremely low. All remaining GE units are projected to reach the starts limits beyond the current PSA contract expiration date of 2028.

The National Grid machinery insurance carrier has accepted this program.

# APPENDIX 1.1

## National Grid Electric Generation Scorecards (Steam & CT)

## National Grid Steam Station Units


### E.F. Barrett Unit 1

**Executive Summary:**


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

Managed Systems				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	Work Order	Work Order	Spare Parts	
Financial Planning				Comments: The 2014 thru 2018 Capital Budget for the Barrett Station is in excess of [REDACTED]
Base	Outage	Capital		
Material Condition/Major Systems				Comments: At present, the mooring cells at the fuel oil barge delivery dock are not capable of receiving fuel oil deliveries. A Capital Work Order for the mooring cells and dock repairs [REDACTED] has been approved for the Fall of 2014. Section 316b of the Federal Clean Water Act could require a significant tower steam condensing for both 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. National Grid has proposed VSD for Circ. Water Pumps and Fish Friendly Traveling Screens.
Forced Air	Environmental			
Service Water	Circ Water	Inst Air		
Service Air	Condensate	Feedwater		
Vacuum	Seal Stream	Water Treatment		
Extraction Steam	Elec Distribution	DCS		
Material Condition/Major Components				Comments: Factory Mutual Boiler Inspection in 2014 did not identify any major problems with the boiler and accessories; however, the age of the boiler piping and headers requires continual monitoring and replacements. Headers, pendants and tube banks have been replaced during the past ten years and National Grid will be replacing the units LTSH Upper Bank and economizer bank in 2014 and 2016, respectively.
Turbines	Generators	Boilers		
Breakers	Transformers	Piping		
Stack				

**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 Steam Station Units

### E.F. Barrett Unit 2

**Executive Summary:**

E.F. Barrett Unit 2 is a 175 MWG unit placed in initial operation in 10/24/63. The unit is equipped with a GE turbine/generator and Combustion Engineering tangential fired steam boiler which will fire natural gas or #6 low sulphur residual oil. Summer availability from 2003 to 2013 has been greater than 98%. In 2013, the summer availability was reduced due to the extension of a summer preparation outage extending into the summer months. The unit EFORD for the past 10 years has been below 5%. In 2012, the Station EFORD was 13% as a result of substation flooding after Super Storm Sandy. The Station average Capacity Factor for the past five years was approximately 33%. A 650 MW combined cycle unit has been proposed the replacement of both Barrett steam units.

Managed Systems				Comments: Operations and maintenance procedures are in place. The maintenance work management system (CMMS) is used to identify, plan, schedule, document execution & maintain history for all DM & PM.
Operations	Maintenance	Work Mgt	Spare Parts	
Financial Planning				Comments: The 2014 thru 2018 Capital Budget for the Barrett Station is in excess of [REDACTED]
Base	Outage	Capital		
Material Condition/Major Systems				Comments: At present, the mooring cells at the fuel oil barge delivery dock are not capable of receiving fuel oil deliveries. A Capital Work Order for the mooring cells and dock repairs for [REDACTED] has been approved for the Fall of 2014. Section 316b of the Federal Clean Water 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.
Forced Air	Circ Water	Inst Air	Environmental	
Service Water	Condensate	Feedwater		
Service Air	Seal Stream	Water Treatment		
Vacuum	Elec Distribution	DCS		
Extraction Steam				
Material Condition/Major Components				Comments: Factory Mutual Boiler Inspection in 2014 did not identify any major problems with the boiler and accessories; however, the age of the boiler piping and headers requires continual monitoring and replacements. Headers, pendants and tube banks have been replaced during the past ten years and National Grid will be replacing the units asphalt tubing in 2015.
Turbines	Generators	Boilers		
Breakers	Transformers	Piping		
Stack				

**Will Meet Contractual Performance Requirements As Planned and Financed through 2012**

<div style="background-color: red; width: 40px; height: 20px; margin: 0 auto;"></div> <p>Not without Major Intervention</p>	<div style="background-color: yellow; width: 40px; height: 20px; margin: 0 auto;"></div> <p>Threatened without Minor Intervention</p>	<div style="border: 1px solid black; width: 40px; height: 20px; margin: 0 auto;"></div> <p>Yes</p>	<div style="background-color: #808000; width: 40px; height: 20px; margin: 0 auto;"></div> <p>More than Adequate</p>
---	---	--	---



# National Grid Steam Station Units

## Northport Unit 1

### Executive Summary:

Northport Unit 1 is a 375 MW/G 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 Iroquois 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				Spare Parts	Comments
Operations	Maintenance	Work Mgt	Financial Planning		
Base	Outage	Capital			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.
Material Condition/Major Systems					Comments: The 2014 thru 2018 Capital Budget for the Northport Station is in excess of [REDACTED]
Fuel Delivery	Forced Air	Environmental			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 Water Act could require cooling towers steam condensing for all Northport units which would require a significant capital expenditure (estimated at [REDACTED]). Permit has not been issued by NYSDEC and it is expected that a capital investment decision for cooling towers will be beyond the 5 year assessment period. DCS upgrade to NERC-CIP requirements in 2014.
Service Water	Circ Water	Inst Air			
Service Air	Condensate	Feedwater			
Vacuum	Seal Stream	Water Treatment			
Extraction Steam	Elec Distribution	DCS			
Material Condition/Major Components					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 Requirements As Planned and Financed through 2019

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



## National Grid Steam Station Units

### Northport Unit 2

**Executive Summary:**

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

Managed Systems				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 Mfg	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 Water 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 NOx 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 Requirements As Planned and Financed through 2012**

<div style="background-color: red; width: 40px; height: 20px; margin: 0 auto;"></div> <p>Not without Major Intervention</p>	<div style="background-color: yellow; width: 40px; height: 20px; margin: 0 auto;"></div> <p>Threatened without Minor Intervention</p>	<div style="border: 1px solid black; width: 40px; height: 20px; margin: 0 auto;"></div> <p>Yes</p>	<div style="background-color: green; width: 40px; height: 20px; margin: 0 auto;"></div> <p>More than Adequate</p>
---	---	--	---

## 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				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 Water 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 NOx 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 Requirements As Planned and Financed through 2019**

<div style="border: 1px solid black; width: 50px; height: 20px; background-color: red; margin: 0 auto;"></div> <p>Not without Major Intervention</p>	<div style="border: 1px solid black; width: 50px; height: 20px; background-color: yellow; margin: 0 auto;"></div> <p>Threatened without Minor Intervention</p>	<div style="border: 1px solid black; width: 50px; height: 20px; background-color: white; margin: 0 auto;"></div> <p>Yes</p>	<div style="border: 1px solid black; width: 50px; height: 20px; background-color: green; margin: 0 auto;"></div> <p>More than Adequate</p>
--	--	---	--

# 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				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.
Operations	Maintenance	Work Mat			
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 Water 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 NYSDCE 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 NOx 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 wall upgrade in 2018. Stack muffler upgrade in 2017.
Turbines	Generators	Boilers			
Breakers	Transformers	Piping			
Stack					

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

**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 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 constrained 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				Comments
Operations	Maintenance	Work Mat	Spare Parts	
Financial Planning				Comments: The 2014 thru 2018 Capital Budget for the Port Jefferson Station is in excess of [REDACTED]
Base	Outage	Capital		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.
Material Condition/Major Systems				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.
Fuel Delivery	Forced Air	Environmental		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.
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		
Breakers	Transformers	Piping		
Stack				

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

## 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, initial 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 Order	Spare Parts
Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.			
Base	Outage	Capital	
The 2014 thru 2018 Capital Budget for this station is in excess of [REDACTED]			
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.			
Fuel Storage	Start Systems	Environmental	
Control Systems	Elec.Distribution	Structures	
Fire Protection			
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.			
Material Condition/Major Components			
Comb. Turbines	Compressors	Generators	
Breakers	Transformers	Stacks	
Inlet ducts		Rotors	

### 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

## 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 Vite	Spare Parts	
Financial Planning				The 2014 thru 2018 Capital Budget for this station is
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	Visual Inspection	W. & M. Test	Spare Parts
Financial Planning			
Base	Outage	Capital	
Material Condition/Major Systems			
Fuel Storage	Start Systems	Environmental	
Control Systems	Elec.Distribution	Structures	
Fire Protection			
Material Condition/Major Components			
Comb. Turbines	Compressors	Generators	
Breakers	Transformers	Stacks	
Inlet ducts			


Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.

There are no schedule Capital Improvement project planned for this station at this time.

Satisfactory.

Satisfactory. As noted above, compressor blade HCF issues need to be monitored going forward. This issue is being addressed under OEM warranty.

### 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 (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 Mfg	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 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

## Holtville 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. Capital 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	Information	Work M3	Spare Parts
Financial Planning			
Base	Outage	Capital	
Material Condition/Major Systems			
Fuel Storage	Start Systems	Environmental	
Control Systems	Elec.Distribution	Structures	
Fire Protection			
Material Condition/Major Components			
Comb. Turbines	Compressors	Generators	
Breakers	Transformers	Stacks	
Inlet ducts			

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]

Satisfactory. These units have recently been improved by adding water injection for NOx control. Refer to Control System comments in Executive Summary above.

Satisfactory. Stacks and inlet ducts requiring attention are addressed in the Capital Projects five (5) year plan.

### 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

## 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 unattended. 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 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

## 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				Spare Parts	Operations and maintenance procedures in place are excellent, providing planning, scheduling, execution and equipment history.
Operations	Maintenance	Work Mgt	Financial Planning		
Base	Outage	Capital			The 2014 thru 2018 Capital Budget for this unit is in excess of [REDACTED]
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 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

## Southold GT Unit (1)

### Executive Summary:

This site consists of one (1) unit. This unit is a General Electric model Frame SJ 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. The 2014 thru 2018 Capital Budget for this unit is in excess of [REDACTED]
Operations	Maintenance	Work Order	Spare Parts	
Financial Planning				Satisfactory. General cosmetic appearance (painting) attention is required and planned for the enclosure. Refer to Control System comments in Executive Summary above.
Base	Outage	Capital		
Material Condition/Major Systems				
Fuel Storage	Start Systems	Environmental		
Control Systems	Elec.Distribution	Structures		
Fire Protection				Satisfactory.
Material Condition/Major Components				
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

## 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 Vets	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			
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

## 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 <span style="background-color: black; color: black;">[REDACTED]</span>
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 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

## 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 Requirements As Planned and Financed through 2019



Not without Major Intervention



Threatened without Minor Intervention



Yes



More than Adequate

# APPENDIX 1

## National Grid Gas Turbine and Diesel Units



### Northport APG Unit

#### Executive Summary:

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

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

#### Will Meet Contractual Performance Requirements 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-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.

#### Early 1990s

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. Forty-two (42) adjacent side wall tubes were replaced from elevation 128'-0" to 152'-9" on both north and south sides. Removal of the radiant front wall SH required in the installation of a new roof junction inlet header and relocation of the intermediate desuperheater spray station from the inlet to outlet of the division panels. This relocation was necessary because it would be useless to spray right after the drum since the steam is saturated. Redesign of the desuperheater liners included relocation of the

penetration set screw from the middle to upstream portion to allow for thermal growth. The mounting pads were also upgraded to stellite material. The steam drums were modified from 2 to 4 rows of dryers which matches the Unit 3 and 4 designs. Further enhancements included the upgrade from slot to propeller type primary separators and from corrugated plate to dish type secondary separators. The Unit 2 pendant platen SH was replaced with material upgrades. These upgrades included changing the T1 to T11 and the T11 to T22. The inner hairpin and wrapper's tube lower portion was upgraded to stainless steel. The Unit 2 intermediate pendant spaced SH was fully replaced. This included material upgrades from T11 to T22 and extending back the 347H stainless steel portion, replacement of all DMW in its outlet, and surface reduction to the second loop to reduce sprays. The only major SNAP recommendation that was not implemented was increasing surface in the horizontal reheater to help make the required 1005F reheat steam temperature. Since this mod was not implemented, burner tilts and gas recirculation (GR) fan operations are used to raise the reheat steam temperature. However, there is limit to its effectiveness since higher GR flow and tilts also raises the SH sprays. Resized windbox/burner buckets and added close coupled overfire air (CCOFA) for NOx control. The CCOFA buckets were equipped with manual horizontal YAW adjustment. Removed bricking in the auxiliary air compartments. After start-up, it was initially difficult to achieve main steam temperature because the furnace was not "seasoned".

#### Mid-Late 1990s

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

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

For Unit 1, the SNAP modification was implemented in 1994 followed by the addition of gas firing capability in 1998. During the Unit 1 SNAP modifications, some front and rear P.S. superheater assemblies and selective individual tubing

were replaced due to previous failures. The Unit 2 SNAP work was implemented in 1992 followed with additional of gas firing in 1995. The few implemented boiler modification differences performed on Unit 1 as compared to Unit 2 are shown in the Listing of Modifications. It should be noted that all burner buckets on all four Units are now the same size and design resulting in one set of spare parts. This is true even on Unit 3 where partial gas firing was added later.

### 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 inconel 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 from 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.

#### 2007-2008

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**

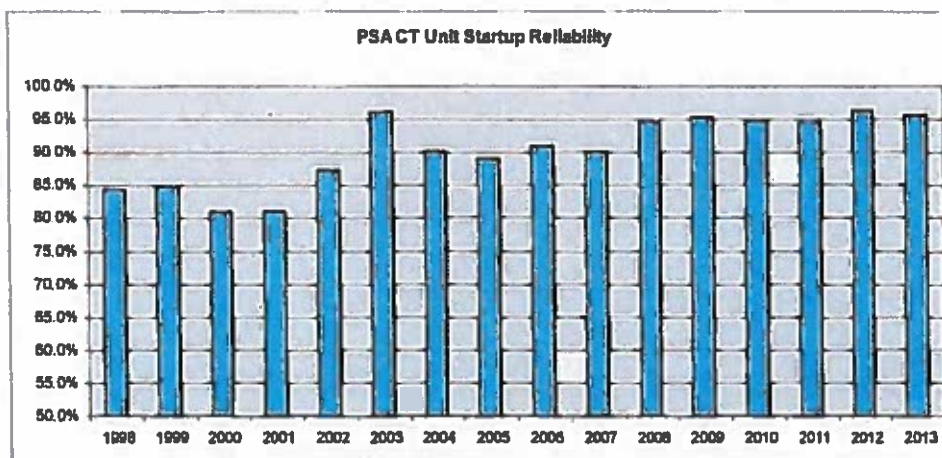
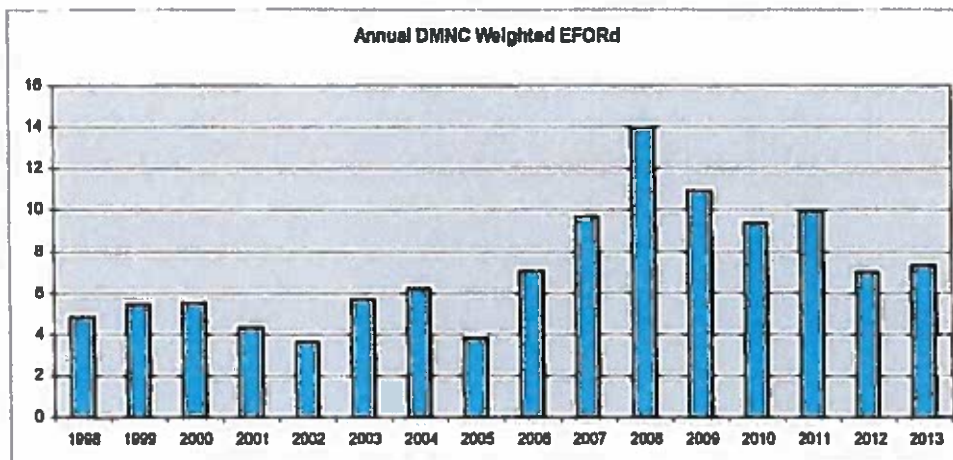
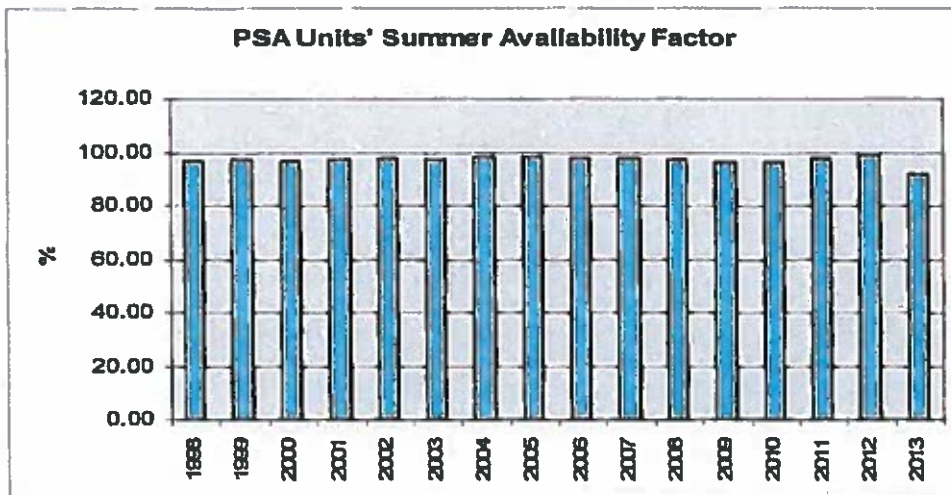
- a. CT 2015 to 2019 Generation Preliminary 5 yr Capital Budget LIPA PSA submittal 7-10-14**
- b. PPO Major Capital Improvements Gas Turbines by unit 8-21-14**
- c. 10b hot Section**
- d. Final Shop Report 018860 Nat Grid FT4A P675476**

- 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**





## Repowering Feasibility Study

---

### Appendix D. 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 Barrett. 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 D.



## Repowering Feasibility Study

---

### Appendix E. 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.