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2017 PSE Integrated Resource Plan

Gas-fired Resource Costs

The attached report developed for PSE by Black & Veatch presents generic order-of-magnitude cost and performance estimates and other plant characteristics for natural gas-fired power plant options.

Contents

FINAL REPORT

CHARACTERIZATION OF SUPPLY SIDE OPTIONS

Natural Gas-Fired Options

B&V PROJECT NO. 192143
B&V FILE NO. 40.1100

PREPARED FOR

Puget Sound Energy

12 JANUARY 2017

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1.0 Introduction

Puget Sound Energy (PSE) is currently developing information that will be used to complete the next iteration of the company's Integrated Resource Plan (IRP). PSE has tasked Black & Veatch to characterize current, competitive natural gas-fired power plant options. These options will be considered as supply-side options (SSOs) within the upcoming IRP.

1.1 BACKGROUND

In 2012 on behalf of PSE, Black & Veatch developed the 2012 Gas-Fired Power Plant Characteristics report, which presented generic order-of-magnitude cost and performance estimates and other plant characteristics for natural gas-fired power plant options. The 2012 report was updated by Black & Veatch in 2014. In 2016, PSE has again requested that Black & Veatch provide current characteristics for relevant SSOs to be considered in the current IRP process.

1.2 OBJECTIVE

The objective of this report is to provide a general overview of the commercially available baseload and peaking gas-fired SSOs. This overview includes order-of-magnitude estimates of performance and cost for Greenfield installations as well as peaking unit additions at an existing PSE generating facility.

1.3 APPROACH

As with prior reports, the information and data presented herein are intended to be preliminary, screening-level characteristics suitable for the initial evaluation of multiple SSOs. In the event that a particular SSO is deemed cost-competitive or selected for further investigation, these estimates may be refined in subsequent stages of planning and development.

The screening-level performance and cost estimates have been developed based on experience with similar generation options, including both recent studies and recent project installations executed by Black & Veatch. Where applicable, Black & Veatch has incorporated recent performance and cost data provided by major equipment Original Equipment Manufacturers (OEMs). This information has been adjusted using engineering judgment to provide values that are considered representative for potential projects that may be implemented by PSE within its service territory.

1.4 REPORT ORGANIZATION

Following this Introduction, this report is organized as follows:

- Section 2.0 – Study Basis and General Assumptions
- Section 3.0 – Gas-Fired Generation Option Descriptions
- Section 4.0 – Summary of Performance and Emission Estimates
- Section 5.0 – Summary of Capital and O&M Cost Estimates

- Appendix A – Full Thermal Performance Estimates for Supply-Side Options
- Appendix B – Air-Cooled Design Considerations
- Appendix C – Supplemental HRSG Duct Firing
- Appendix D – Peaking Plant Backup Fuel
- Appendix E – Capital and O&M Cost Estimates for Brownfield Projects
- Appendix F – Wartsila Recommended Maintenance Intervals

2.0 Study Basis and General Assumptions

In support of its current IRP effort, PSE has selected to characterize eight gas-fired SSOs, including two (2) combined cycle options and six (6) simple cycle options. Combined cycle options would operate as Baseload units, while simple cycle options would operate as Peaking units.

Combined cycle options selected for consideration by PSE include:

- **Combined Cycle A:** GE 7F.05 combustion turbine generator (CTG) in a 1x1 configuration
- **Combined Cycle B:** GE 7HA.01 CTG in a 1x1 configuration

Simple cycle options selected for consideration by PSE include:

- **Peaking Plant A:** Wartsila 18V50SG reciprocating internal combustion engine (RICE) in a 3x0 configuration
- **Peaking Plant B:** Wartsila 18V50SG RICE in a 6x0 configuration
- **Peaking Plant C:** Wartsila 18V50SG RICE in a 12x0 configuration
- **Peaking Plant D:** GE LMS100PA+ CTG in a 1x0 configuration
- **Peaking Plant E:** GE LMS100PA+ CTG in a 2x0 configuration
- **Peaking Plant F:** GE 7F.05 CTG in a 1x0 configuration

The options are similar to combined cycle and peaking plant options characterized in 2014. Combined cycle options (Combined Cycles A and B) utilize current, commercial large frame CTGs as the prime mover for the facility. Peaking plant options include facilities employing reciprocating engines (Peaking Plants A, B and C), aeroderivative CTGs (Peaking Plants D and E); and large frame CTGs (Peaking Plant F).

The selected gas turbine SSOs are assumed to employ turbines supplied by General Electric (GE), while the selected reciprocating engine SSOs are assumed to employ engines supplied by Wartsila. These assumptions were made to provide a consistent comparison within these technology classes. Identification of these OEMs is not intended to be an implicit recommendation or final technology selection. In the event that a given SSO may be selected for development, it is recommended that PSE consider all qualified technology suppliers. For example, if PSE elected to investigate large frame CTG options in subsequent stages of planning and development, it is recommended that PSE consider combustion turbine options offered by GE, Mitsubishi Hitachi Power Systems and Siemens.

2.1 DESIGN BASIS FOR SUPPLY SIDE OPTIONS

Design basis parameters for the selected SSOs are summarized for combined cycle options in Table 2-1 and for peaking plant options in Table 2-2.

Table 2-1 Design Basis Parameters for Combined Cycle SSOs

OPTION ID	SUPPLY-SIDE OPTION	PLANT CONFIGURATION	DUTY	AVERAGE AMBIENT NET OUTPUT (MW)	ANNUAL CAPACITY FACTOR (%)	ANNUAL NUMBER OF STARTS
CC-A	1x1 GE 7F.05	Combustion Turbine: GE 7F.05 Inlet Air Cooling: None HRSG: Triple Pressure , Reheat Duct Firing: None Emissions Control: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Baseload	359	80	70
CC-B	1x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Inlet Air Cooling: None HRSG: Triple Pressure, Reheat Duct Firing: None Emissions Control: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Baseload	405	80	70

Table 2-2 Design Basis Parameters for Peaking Plant SSOs

OPTION ID	SUPPLY-SIDE OPTION	PLANT CONFIGURATION	DUTY	AVERAGE AMBIENT NET OUTPUT (MW)	ANNUAL CAPACITY FACTOR (%)	ANNUAL NUMBER OF STARTS
PP-A	3x0 Wartsila 18V50SG	Recip. Engine: Wartsila 18V50SG Emissions Control: SCR, CO catalyst Heat Rejection: Closed-Loop Radiator	Peaking	55	5	100
PP-B	6x0 Wartsila 18V50SG	Recip. Engine: Wartsila 18V50SG Emissions Control: SCR, CO catalyst Heat Rejection: Closed-Loop Radiator	Peaking	111	5	100
PP-C	12x0 Wartsila 18V50SG	Recip. Engine: Wartsila 18V50SG Emissions Control: SCR, CO catalyst Heat Rejection: Closed-Loop Radiator	Peaking	222	5	100
PP-D	1x0 GE LMS100PA+	Comb. Turbine: GE LMS100PA+ Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Peaking	114	6	100
PP-E	2x0 GE LMS100PA+	Comb. Turbine: GE LMS100PA+ Emissions Control: SCR, CO catalyst, Heat Rejection: Wet Cooling Tower	Peaking	227	6	100
PP-F	1x0 GE 7F.05	Combustion Turbine: GE 7F.05 Inlet Air Cooling: None Emissions Control: SCR, CO catalyst Heat Rejection: Std Package (Dry)	Peaking	239	2	100

2.2 GENERAL SITE ASSUMPTIONS

In addition to the design basis parameters shown in Table 2-1 and Table 2-2, general site assumptions employed by Black & Veatch for these SSOs include the following:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- The plant will not be located on environmentally or culturally sensitive lands. The project site will require neither mitigation nor remediation.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- Potable, Service and Fire water will be supplied from the local water utility.
- Cooling water, if required, will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Natural gas pressure at the site boundary is assumed to be about 400 psi.
  - At this delivery pressure, all frame combustion turbine (i.e., 7F.05 and 7HA.01) and aeroderivative combustion turbine (i.e., LMS100PA+) options will require fuel gas compression.
  - Reciprocating engine-based options will not require fuel gas compression.
- Costs for transmission lines and switching stations are included as part of the owner's cost estimate.

2.3 CAPITAL COST ESTIMATING BASIS

Screening-level capital cost estimates were developed for each of the SSOs evaluated. The capital cost estimates were developed based on Black & Veatch's experience on projects either serving as engineering, procurement, and construction (EPC) contractor or as owner's engineer (OE). Capital cost estimates are market-based; based on recent and on-going experiences. The market-based numbers were adjusted based on technology and configuration to arrive at capital cost estimates developed on a consistent basis and reflective of current market trends.

Rather than develop capital cost estimates based on a "bottoms up" methodology, the estimates presented herein have been developed using recent historical and current project pricing and then adjusted to account for differences in region, project scope, technology type, and cycle configuration. The basic process flow is as follows:

- **Leverage** in-house database of project information from EPC projects recently completed and currently being executed as well as EPC pursuits currently being bid and our knowledge of the market from an owner's engineer perspective to produce a list of potential reference projects based primarily on technology type and cycle configuration.

- **Review** differences in region and scope.
- **Exclude** references which differ significantly from study basis.
- **Adjust.** The remaining references are broken down into several cost categories and further adjusted to account for differences such as major equipment pricing, labor, and commodities escalation.
- **Scale.** Remaining reference projects are compared and a scaling curve is generated. That scaling curve forms the basis for the screening-level capital cost estimates and is ultimately used to arrive at the EPC capital cost estimate.

The estimate process described above maximizes the value of past experiences and reduces bias resulting from project outliers such as differences in scope and location with the objective of providing current market pricing for generic power projects in PSE's service territory.

Capital cost estimates presented in Section 5.0 are based on Greenfield site development under fixed, lump sum EPC contracting. Cost estimates are on a mid-year 2016 US dollars basis. EPC cost estimates are based on Black & Veatch's knowledge of current market trends. Financing fees, interest during construction, land, outside-the-fence infrastructure, and taxes are considered to be "Owner Costs" and need to be added to the EPC cost estimates to arrive at a total installed cost. For this study, the allowance for Owner's costs is assumed to be 30 percent. A more comprehensive listing of potential owner costs is presented in Table 2-3.

Table 2-3 Potential Owner's Costs for Power Generation Projects

Project Development
• Site selection study
• Land purchase/rezoning for greenfield sites
• Transmission/gas pipeline right-of-way
• Road modifications/upgrades
• Demolition
• Environmental permitting/offsets
• Public relations/community development
• Legal assistance
• Provision of project management
	Owner's Contingency
	• Owner's uncertainty and costs pending final negotiation:
	  • Unidentified project scope increases
	  • Unidentified project requirements
	  • Costs pending final agreements (i.e., interconnection contract costs)

Spare Parts and Plant Equipment • Combustion and steam turbine materials, supplies and parts • HRSG and/or boiler materials, supplies and parts • SCR and CO catalyst materials, supplies and parts • Balance-of-plant equipment/tools • Rolling stock • Plant furnishings and supplies • Recip. engine materials, supplies and parts	**Owner's Project Management** • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management **Taxes/Advisory Fees/Legal** • Taxes • Market and environmental consultants • Owner's legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property
Plant Startup/Construction Support • Owner's site mobilization • O&M staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Cost of fuel not recovered in power sales • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance	**Utility Interconnections** • Natural gas service • Gas system upgrades • Electrical transmission (including switchyard) • Water supply • Wastewater/sewer **Financing (may be included in fixed charge rate)** • Financial advisor, lender's legal, market analyst, and engineer • Interest during construction • Loan administration and commitment fees • Debt service reserve fund

2.4 NON-FUEL OPERATING & MAINTENANCE COST ESTIMATING BASIS

Black & Veatch developed non-fuel operations and maintenance (O&M) cost estimates for each option under consideration. Non-fuel O&M cost estimates were developed as representative estimates based on (1) previous Black & Veatch experience with projects of similar design and scale, and (2) relevant vendor information available to Black & Veatch. Non-fuel O&M cost estimates were categorized into Fixed O&M and Non-fuel Variable O&M components:

- Fixed O&M costs include labor, routine maintenance and other expenses (i.e., training, property taxes, insurance, office and administrative expenses).
- Non-fuel Variable O&M costs include outage maintenance (including the costs associated with Long Term Service Agreements [LTSAs] or other maintenance agreements), parts and materials, water usage, chemical usage and equipment.
- Non-fuel Variable O&M costs exclude the cost of fuel (i.e., natural gas).

Additional assumptions regarding O&M cost estimates include the following:

- Plant staffing assumptions are summarized in Table 2-4 for Greenfield options.
- Labor rates for O&M staff were assumed based on information provided by PSE and Black & Veatch experience with similar facilities in the Pacific Northwest.
- All plant water consumption (including cooling water) was assumed to be sourced from a nearby water utility. Water rates were assumed as follows:
    - Monthly basic fixed charge of $1209.05.
    - Rate for first 100 ccf (100 cubic feet) of water consumed per month: $3.95 per ccf.
    - Rate for quantity greater than 100 ccf per month: $2.31 per ccf.
- Cost for additional plant consumables based on information provided by PSE and Black & Veatch experience with similar facilities in the region.
- All non-fuel O&M cost estimates are presented in 2016 dollars.

Table 2-4 Plant Staffing Assumptions for Greenfield Options

ID	OPTION	GREENFIELD STAFFING (FTEs)
CC-A	1x1 GE 7F.05	17
CC-B	1x1 GE 7HA.01	17
PP-A	3x0 Wartsila 18V50SG	9
PP-B	6x0 Wartsila 18V50SG	9
PP-C	12x0 Wartsila 18V50SG	12
PP-D	1x0 GE LMS100PA+	9
PP-E	2x0 GE LMS100PA+	9
PP-F	1x0 GE 7F.05	9

3.0 Gas-Fired Generation Option Descriptions

As noted in Section 2.0, PSE has selected to characterize SSOs that employ the following gas-fired generation prime mover technologies:

- GE 7F.05 CTG
- GE 7HA.01 CTG
- Wartsila 18V50SG reciprocating engine
- GE LMS100PA+ CTG

These gas-fired options are described in the following subsections.

3.1 GE 7F.05

3.1.1 Technology Overview

The 7F.05 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 3-stage axial turbine, and 14-can-annular dry low NO_x (DLN) combustors. The 7F.05 is GE's 5th generation 7FA machine; the latest advancements integrated into the 7F.05 design include a redesigned compressor and three variable stator stages and a variable inlet guide vane for improved turndown capabilities. GE's 7F fleet of over 800 units has over 33 million operating hours.

Key attributes of the GE 7F.05 include the following:

- High availability.
- 40 MW/min ramp rate.
- Start to 200 MW in 10 minutes, full load in 11 minutes (excluding purge).
- Natural gas interface pressure requirement of 435 psig.
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 9 ppm on natural gas.
- Capable of turndown to 45 percent of full load.
- High exhaust temperature increases the difficulty of implementing post-combustion NOx emissions controls (i.e., SCR).

3.1.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for the following configurations:

- **CC-A:** a 1x1 combined cycle natural gas-fired GE 7F.05 combustion turbine facility.
- **PP-F:** a simple cycle (1x0) natural gas-fired GE 7F.05 combustion turbine facility.

Relevant assumptions employed in the development of performance and cost parameters for 7F.05 options include the following:

- For the CC-A option:
  - The power plant would consist of a single GE 7F.05 CTG, located outdoors in a weather-proof enclosure; the CTG would be close-coupled to a three-

pressure HRSG. Ancillary CTG skids would also be located outdoors in weather-proof enclosures.

  - An axial flow reheat condensing steam turbine would accept steam from the HRSG at three pressure levels. The steam turbine would be located within a building.
  - A wet surface condenser and mechanical draft counterflow cooling tower would reject STG exhaust heat to atmosphere.
  - To reduce NOx and carbon monoxide (CO) emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would be located within the HRSG in a temperature region conducive to the SCR catalyst.
  - A generation building would house electrical equipment, balance of plant controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- For the PP-F option:
  - The power plant would consist of a single GE 7F.05 CTG, located outdoors in a weather-proof enclosure. Ancillary CTG skids would also be located outdoors in weather-proof enclosures.
  - To reduce NOx and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would include purge/tempering air for startup and to reduce CTG exhaust temperature to within the operational limits of the SCR catalyst.
  - A generation building would house electrical equipment, balance of plant controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compression (to approximately 500 psia) has been assumed for 7F.05 options.

3.2 GE 7HA.01

3.2.1 Technology Overview

The GE 7HA.01 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 4-stage axial turbine, and 12-can-annular DLN combustors. The 7HA.01 has a single inlet guide vane stage and three variable stator vain stages to vary compressor geometry for part load operation. The 7HA.01 and the scaled-up 7HA.02 represent the largest and most advanced heavy frame CTG technologies from GE. (GE also offers 50 Hz versions, the 9HA.01 and 9HA.02.) The compressor design is scaled from GE's 7F.05 and 6F.01 (formally 6C) designs. The 7HA.01 employs the DLN 2.6+ AFS (Axial Fuel Staged) fuel staging combustion system which allows for high firing temperatures and improved gas turbine turndown while maintaining emissions guarantees; providing stable operations; and allowing for increased fuel variability.

The 7HA.01 and the 7HA.02 are the newest combustion turbine technologies offered by GE. The first shipments of the 7HA.01 are expected in 2016 (to Chubu Electric's Nishi-Nagoya thermal power plant in Nagoya City, Japan). GE has more than 16 orders of its HA CTG technology to date.

Key attributes of the GE 7HA.01 include the following:

- High availability.
- CTG 50 MW/min ramp rate.
- Capable of turndown to approximately 30 percent of full load (ambient temperature dependent).
- Natural gas interface pressure requirement of about 540 psig.
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 25 ppm on natural gas.

3.2.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for:

- **CC-B:** a 1x1 combined cycle natural gas-fired GE 7HA.01 combustion turbine facility.

Relevant assumptions employed in the development of performance and cost parameters for the 1x1 7HA.01 option include the following:

- The power plant would consist of a single GE 7HA.01 CTG, located outdoors in a weather-proof enclosure; the CTG would be close-coupled to a three-pressure HRSG. Ancillary CTG skids would also be located outdoors in weather-proof enclosures.
- An axial flow reheat condensing steam turbine would accept steam from the HRSG at three pressure levels. The steam turbine would be located within a building.
- A wet surface condenser and mechanical draft counterflow cooling tower would reject STG exhaust heat to atmosphere.
- To reduce NOx and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would be located within the HRSG in a temperature region conducive to the SCR catalyst.
- A generation building would house electrical equipment, balance of plant controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compression (to approximately 600 psia) has been assumed for this option.

3.3 WARTSILA 18V50SG

3.3.1 Technology Overview

Wartsila's 18V50SG reciprocating engine is a turbocharged, four-stroke spark-ignited natural gas engine. Unlike dual fuel reciprocating engines, the SG does not require liquid pilot fuel during startup and to maintain combustion. The 18V50SG utilizes 18 cylinders in a "V" configuration. Each cylinder has a bore diameter of 500 millimeters (19-11/16 inches) and a stroke of 580 millimeters (22-13/16 inches). Each engine operates at a shaft speed of 514 revolutions per minute. These engines employ individual cylinder computer controls and knock sensors for precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. There have been more than sixty 18V50SG engines sold to date with initial commercial operations starting in 2013.

For this characterization, it is assumed that engine heat is rejected to the atmosphere using an air-cooled heat exchanger, or "radiator." An 18V50SG power plant utilizing air cooled heat exchangers requires very little makeup water as the engines do not typically utilize inlet cooling for power augmentation or water injection for NO_x reduction.

Key attributes of the Wartsila 18V50SG include the following:

- High full- and part-load efficiency.
- Minimal performance impact at hot-day conditions.
- 5 minutes to full power (excluding purge).
- Capable of turndown to 25 percent of full load.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 75 psig.
- Not dual fuel capable.

While the 18V50SG does not provide dual fuel capability, the diesel variation of the engine, the 18V50DF model, does provide dual fuel capability. In diesel mode, the main diesel injection valve injects the total amount of light fuel oil as necessary for proper operation. In gas mode, the combustion air and the fuel gas are mixed in the inlet port of the combustion chamber, and ignition is provided by injecting a small amount of light fuel oil (less than one percent by heat input). The injected light fuel oil ignites instantly, which then ignites the air/fuel gas mixture in the combustion chamber. During startup, the 18V50DF must operate in diesel mode until the engine is up to speed; once up to speed, the unit may operate in gas mode.

Wartsila offers a standard, pre-engineered six-engine configuration for the 18V50SG and the 18V50DF, sometimes referred to as a "6-Pack". The 6-Pack configuration has a net generation output of approximately 110 MW and ties the six engines to a single bus and step-up transformer. This configuration provides economies of scale associated with the balance of plant systems (e.g., step-up transformer and associated switchgear) and reduced engineering costs.

3.3.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for the following configurations:

- **PP-A:** 3x0 (simple cycle) natural gas-fired Wartsila 18V50SG RICE facility.
- **PP-B:** 6x0 (simple cycle) natural gas-fired Wartsila 18V50SG RICE facility.
- **PP-C:** 12x0 (simple cycle) natural gas-fired Wartsila 18V50SG RICE facility.

Relevant assumptions employed in the development of performance and cost parameters for 7F.05 options include the following:

- For the PP-A option:
  - The facility would consist of three (3) Wartsila 18V50SG reciprocating engines, arranged as slide along units and co-located in a common engine hall.
- For the PP-B option:
  - The facility would consist of six (6) Wartsila 18V50SG reciprocating engines, arranged as slide along units and co-located in a common engine hall.
- For the PP-C option:
  - The facility would consist of twelve (12) Wartsila 18V50SG reciprocating engines, arranged as slide along units and co-located in a common engine hall.
- For all three 18V50SG options:
  - The engine hall would be one of a number of rooms within a generation building. The generation building would also include space for electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
  - An SCR system with oxidation catalyst would be utilized to minimize NOx and CO emissions.
  - Engine heat is rejected to atmosphere by way of a closed loop radiators. The use of these radiators would make water consumption rates of the Wartsila engines negligible.
- No natural gas compression has been assumed for 18V50SG options.

3.4 GE LMS100PA+

3.4.1 Technology Overview

The LMS100 is an intercooled aeroderivative CTG with two compressor sections and three turbine sections. Compressed air exiting the low-pressure compressor section is cooled in an air-to-water intercooler heat exchanger prior to admission to the high-pressure compressor section. A mixture of compressed air and fuel is combusted in a single annular combustor. Hot flue gas then enters the two-stage high-pressure turbine. The high-pressure turbine drives the high-pressure compressor. Following the high-pressure turbine is a two-stage intermediate pressure turbine, which drives the low-pressure compressor. Lastly, a five-stage low-pressure turbine drives the electric generator. Major intercooler components include the inlet and outlet scrolls and associated ductwork to/from the intercooler and the intercooler. Nitrogen oxides (NO_x) emissions are minimized utilizing water injection (for the LMS100PA+) or the use of Dry Low Emission (DLE) combustion technology (for the LMS100PB+).

Many of the major components from the LMS100 are based on engine applications with extensive operating hours. The low-pressure compressor section is derived from the first six stages of GE's MS6001FA heavy-duty CTG compressor. The high-pressure compressor is derived from GE's CF6-80C2 aircraft engine and strengthened to withstand a pressure ratio of approximately 41:1. The single annular combustor and high pressure turbine are derived from GE's LM6000 aeroderivative turbine and CF6-80C2 and CF6-80E2 aircraft engines.

Key attributes of the GE LMS100PA include the following:

- High full- and part-load efficiency.
- Minimal performance impact at hot-day conditions.
- High availability.
- 50 megawatt per minute (MW/min) ramp rate.
- 8 minutes to full power (excluding purge).
- Capable of turndown 25 percent of full load.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 850 pounds per square inch gauge (psig).
- Dual fuel capable.

The LMS100 is available in a number of configurations. Major variations include an intercooler heat rejection to atmosphere using dry cooling methods and dry low emissions (DLE) in lieu of water injected combustion for applications when water availability is limited.

GE has recently introduced the LMS100PA+ and LMS100PB+, which provide increased turbine output and a reduced net plant heat rate relative to the LMS100PA and LMS100PB models.

3.4.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for the following configurations:

- **PP-D:** a 1x0 simple cycle natural gas-fired LMS100PA+ combustion turbine facility.
- **PP-E:** a 2x0 simple cycle natural gas-fired LMS100PA+ combustion turbine facility.

Relevant assumptions employed in the development of performance and cost parameters for the LMS100PA+ options include the following:

- For the PP-D (1x0) option:
  - The power plant would consist of a single GE LMS100PA CTG, located outdoors in a weather-proof enclosure.

- For the PP-E (2x0) option:
  - The power plant would consist of two GE LMS100PA CTGs, located outdoors in a weather-proof enclosure.
- To reduce NOx and CO emissions, selective catalytic reduction (SCR) systems with oxidation catalyst would be utilized. The SCR system would include purge/tempering air for startup and when CTG exhaust temperature approaches the operational limits of the SCR catalyst.
- Intercooler heat is rejected to atmosphere by way of wet mechanical draft cooling towers.
- A generation building would house electrical equipment, balance of plant controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compression (to approximately 925 psia) has been assumed for LMS100PA+ options. Natural gas compressors would be housed in a prefabricated weather-proof enclosure.

4.0 Summary of Performance and Emission Characteristics

For each of the SSOs considered in this study, Black & Veatch has developed estimates of unit performance and emissions (when firing pipeline-quality natural gas). Performance estimates were prepared for each SSO at three load points: gas turbine or engine baseload (i.e., 100% Load), intermediate (75%) load, and minimum emissions compliance load (MECL). These estimates were developed considering ambient conditions consistent with locations in the PSE service territory. A summary of the ambient conditions considered for performance estimates is presented in Table 4-1.

Table 4-1 Ambient Conditions for SSO Characterizations

AMBIENT CONDITION	SITE ELEVATION (FT ABOVE MSL)	BAROMETRIC PRESSURE (PSIA)	DRY BULB TEMPERATURE (° F)	RELATIVE HUMIDITY (%)
Typical Low	30	14.68	23	40
Annual Average	30	14.68	51	75
ISO Conditions	0	14.70	59	60
Typical High	30	14.68	88	30

4.1 THERMAL PERFORMANCE AND EMISSIONS ESTIMATES

A summary of unit full load (New and Clean) performance and stack emissions estimates at average day conditions is presented in Table 4. Additional performance cases at full load and part load for three ambient conditions and at ISO conditions are provided in Appendix A of this document. Also included are indicative degradation curves based on generic data, provided by the original equipment manufacturers for past projects.

Combined cycle performance estimates are based on the use of a combination of a surface condenser and wet mechanical draft cooling tower for rejecting heat from the steam bottoming cycle to atmosphere. Performance estimates for simple cycle LMS100PA+ options also utilize wet mechanical draft cooling towers for rejecting heat to atmosphere. Performance estimates for Wartsila 18V50SG options assume that these engines utilize closed-loop radiators (rather than a wet cooling method). A discussion of the performance and cost impacts associated with designing combined cycle and peaking plants with dry cooling heat rejection systems is included in Appendix B.

Combined cycle performance estimates do not include supplemental HRSG duct firing. A discussion of the performance and cost impacts associated with designing combined cycle plants with supplemental HRSG duct firing for increased plant net output is included in Appendix C.

Table 4-2 Full Load (New and Clean) Performance and Stack Emission Estimates at Average Day Conditions

ID	OPTION	NET PLANT OUTPUT (MW)	NET PLANT HEAT RATE (BTU/kWh, HHV)	NO_X EMISSIONS		CO_2 EMISSIONS (LB/HR)
				(PPM)[2]	(LB/HR)	
CC-A	1x1 GE 7F.05	359.1	6,520	2.0	16.8	269,300
CC-B	1x1 GE 7HA.01	405.1	6,410	2.0	18.7	298,500
PP-A	3x0 Wartsila 18V50SG	55.5	8,260	5.0	7.5	53,600
PP-B	6x0 Wartsila 18V50SG	111.0	8,260	5.0	14.9	107,100
PP-C	12x0 Wartsila 18V50SG	222.0	8,260	5.0	29.9	214,200
PP-D	1x0 GE LMS100PA+	113.7	8,810	2.5	9.0	115,100
PP-E	2x0 GE LMS100PA+	227.3	8,810	2.5	18.0	230,200
PP-F	1x0 GE 7F.05	239.0	9,630	2.5	20.7	264,600

Notes:
1. All values based on ambient conditions of 51°F and relative humidity of 75%.
2. NOx emissions on a ppm basis are presented as ppmvd @15% O_2.

4.2 OPERATIONAL CHARACTERISTICS

Operational characteristics for the selected SSOs are presented in this section, including the following parameters:

- Ramp rate, between full load and minimum emission compliant load (MECL)
- Minimum run time upon startup
- Minimum down time upon shutdown
- Start time, to full load
- Loads achievable within 10 minutes (for units with start time greater than 10 minutes)
- Preliminary estimate of startup fuel consumption
- Preliminary estimate of startup net electrical production

4.2.1 Ramping and Run Time Parameters

Ramp rates, minimum run time and minimum downtime are presented for the selected SSOs in Table 4-3.

- Ramp rates are based on capability of each machine to change load between full load and MECL (Minimum Emissions Compliant Load).

- Minimum run time is estimated from the time of generator breaker closure to generator breaker opening. This value is assumed to be limited by CEMS calibration/reporting period. For combined cycle options, minimum run time includes 60 minute allowance for hot start. A longer minimum run time may be required for other start events (i.e., cold start or warm start).
- Minimum downtime is estimated from the time of generator breaker opening to generator breaker closure. These values assume purge and turning gear operation are achieved within one hour.

Table 4-3 Ramp Rate, Minimum Run Time and Minimum Down Time Parameters for SSOs

ID	OPTION	CTG/ENGINE RAMP RATE(1) (MW/MIN)	MINIMUM RUN TIME(2) (MINUTES)	MINIMUM DOWNTIME(3) (MINUTES)
CC-A	1x1 GE 7F.05	40	120	60
CC-B	1x1 GE 7HA.01	50	120	60
PP-A	3x0 Wartsila 18V50SG	42	60	60
PP-B	6x0 Wartsila 18V50SG	84	60	60
PP-C	12x0 Wartsila 18V50SG	168	60	60
PP-D	1x0 GE LMS100PA+	50	60	60
PP-E	2x0 GE LMS100PA+	100	60	60
PP-F	1x0 GE 7F.05	40	60	60

Notes:

1. Ramp Rate based on capability of machine to change load between Full Load and MECL (Minimum Emissions Compliant Load).
2. Minimum Run Time estimated from the time of generator breaker closure to generator breaker opening. This value is assumed to be limited by CEMS calibration/reporting period. For combined cycle options, minimum run time includes 60 minute allowance for hot start. A longer minimum run time may be required for other start events (i.e., cold start or warm start).
3. Minimum Downtime estimated from the time of generator breaker opening to generator breaker closure. These values assume purge and turning gear operation are achieved within one hour.

4.2.2 Unit Start Parameters

Start times are defined as the time required for gas-fired turbines and engines to achieve CTG/RICE full load output from start initiation. Simple cycle CTG and RICE units do not typically have start times that vary depending on the time the unit had previously been offline. However, start times for combined cycle units (and other units that employ steam cycle equipment) do depend upon the time the unit had previously been online. Therefore, start times for combined cycle units may be classified as follows:

- **Hot start:** a start following a shutdown period of less than 8 hours.
- **Warm start:** a start following a shutdown period of 8 – 48 hours.
- **Cold start:** a start following a shutdown period of 48 – 72 hours.
- **Ambient start:** a start following a shutdown period of greater than 72 hours.

Combined cycle unit start times are mainly driven by steam temperature control capabilities and STG warming requirements. Combined cycle CTG and STG start times and ramp rates can be reduced using a number of proven cycle design methods such as integration of auxiliary steam boilers, HRSG stack dampers, steam final point attemperation, and enhanced CTG starting systems.

During the startup period, simple cycle and combined cycle options will consume fuel and electricity and will also produce some quantity of electricity. The amount of fuel consumed and electricity consumed and produced during a startup will impact production costs. After syncing the generator to the grid, the unit will immediately begin generating electricity. If the "Net Electricity Produced" value is positive, then the unit is expected to have produced more electricity than it has consumed.

For both simple cycle and combined cycle options, Table 4-4 presents estimates of start times and estimates of fuel consumption and net electricity production during start up. Combined cycle startup estimates shown in Table 4-4 are based on a hot start and conventional steam cycle designs with no fast start features. Combined cycle starts occurring after longer shutdown periods will require additional time (and fuel) to achieve CTG full load. For example, if the start time under a "hot start" condition is 90 minutes (excluding purge), then the start times under warm, cold and ambient start conditions (excluding purge) would be 150 minutes, 210 minutes and 330 minutes, respectively.

Table 4-4 Startup Parameters for SSOs

ID	OPTION	START TIME[1] (MINUTES)	LOAD ACHIEVABLE IN 10 MINUTES[2] (MW)	FUEL CONSUMP-TION[3] (MBTU, HHV)	NET ELECTRICITY PRODUCED[4] (MWh)
CC-A	1x1 GE 7F.05	90	24	1,000	75
CC-B	1x1 GE 7HA.01	90	28	1,090	85
PP-A	3x0 Wartsila 18V50SG	5	n/a	25	2
PP-B	6x0 Wartsila 18V50SG	5	n/a	50	4
PP-C	12x0 Wartsila 18V50SG	5	n/a	100	7
PP-D	1x0 GE LMS100PA+	8	n/a	42	3
PP-E	2x0 GE LMS100PA+	8	n/a	84	6
PP-F	1x0 GE 7F.05	11.5	200	121	7

Notes:

1. Start Time estimates exclude any time allotted for exhaust system purge.
   Start Time for combined cycle options are based on a hot start and conventional steam cycle designs with no fast start features.
2. For options with start times greater than 10 minutes, Achievable Load represents the load able to be provided within 10 minutes of initiating start of the unit. Wartsila 18V50SG and GE LMS100PA+ are able to achieve full load in less than 10 minutes.
3. Fuel Consumption is the total fuel energy required during startup period
4. Net Electricity Produced is total energy produced during startup period.

5.0 Summary of Capital and Non-Fuel O&M Cost Estimates

Black & Veatch developed order-of-magnitude capital and nonfuel O&M cost estimates for generic Greenfield gas-fired power plants constructed within the state of Washington, based on the SSOs under consideration in this study. Estimates are based on similar studies and project experience and adjusted using engineering judgment.

Along with capital cost estimates, Black & Veatch has also developed estimates of project duration for installation of the selected facilities and incremental cash flows over the duration of project installation.

5.1 INSTALLED CAPITAL COST ESTIMATES

Estimates of capital costs for Greenfield options are presented in Table 5-1. The scope of the cost estimates presented end at the high-side of the generator step-up transformers. Additional costs, including utility interconnections considered outside-the-fence, project development, and project financing are not included in the EPC cost estimates. For each of the considered options, Black & Veatch has included an allowance equal to 30 percent of the EPC capital cost to account for these additional costs, including owner's costs. These additional costs will be discussed in further detail below.

The cost estimates presented are for power plants capable of operating on natural gas fuel only. Having a secondary fuel source for backup, such as diesel fuel, will require additional equipment, systems, and major equipment design accommodations. A discussion of the design and cost impacts associated with designing a peaking plant with backup fuel operation capabilities is included in Appendix D.

Capital costs for development of projects at brownfield locations (i.e., unit additions at existing power generation facilities) are discussed in Appendix E.

Table 5-1 Summary of Capital Cost Estimates (for Greenfield Options)

ID	OPTION	AVERAGE DAY NET OUTPUT(1) (MW)	ESTIMATED EPC COST ($000)	OWNER'S COST ALLOWANCE(2) ($000)	TOTAL OVERNIGHT CAPITAL COST	
					($000)	($/kW)
CC-A	1x1 GE 7F.05	359.1	388,000	116,400	504,400	1,405
CC-B	1x1 GE 7HA.01	405.1	449,000	134,700	583,700	1,440
PP-A	3x0 Wartsila 18V50SG	55.5	61,000	18,300	79,300	1,430
PP-B	6x0 Wartsila 18V50SG	111.0	116,000	34,800	150,800	1,360
PP-C	12x0 Wartsila 18V50SG	222.0	218,000	65,400	283,400	1,275
PP-D	1x0 GE LMS100PA+	113.7	105,000	31,500	136,500	1,200
PP-E	2x0 GE LMS100PA+	227.3	176,000	52,800	228,800	1,005
PP-F	1x0 GE 7F.05	239.0	105,000	31,500	136,500	570

Notes:
1. Average day net output based on ambient conditions of 51°F and relative humidity of 75%.
2. Owner's Cost Allowances are assumed to be equivalent to 30% of Overnight EPC Costs.

As shown in Table 5-1, Black & Veatch has included an allowance equal to 30 percent of the estimated EPC capital cost for each of the options to account for owner's costs and escalation. These additional costs typically range from 20 to 50 percent of the overnight EPC cost and are generally higher for a Greenfield site than a Brownfield site.

Table 5-2 includes a breakdown of typical components of the owner's and escalation cost allowance. This table is presented as an example only to provide PSE with a general understanding of the relative impact of major owner's cost components and escalation. Potential types of owner's costs, including project development and outside-the-fence costs, are presented in Table 2-3.

Table 5-2 Example Owner's Cost and Escalation Breakdown

Cost Component	% of Owner's + Escalation Costs
Utility Interconnections	25%
Owner's Contingency	25%
Interest During Construction	20%
Escalation	10%
Project Development	10%
Other	10%
Total of Owner's and Escalation	**100%**

As evidenced in Table 5-2, outside-the-fence utility interconnections are typically a large component of owner's costs. In addition, earthwork costs can vary significantly depending on soil conditions, impediments, and site terrain. While earthwork is generally placed in the EPC contractor's scope, it is something that can increase project costs above generic Greenfield cost projection. Table 5-3 includes an example of typical values used in Black & Veatch site selection studies to give PSE an understanding of costs associated with major items that influence siting.

Table 5-3 Representative Unit Costs for Outside-the-Fence Utility Interconnections and Siting Considerations

Siting Consideration	Unit	Unit Cost
Earthwork	$/cubic yard of earth displaced	7.50
Water Pipeline	$/mile	500,000 to 750,000
Transmission Line	$/mile	1,000,000
Natural Gas Pipeline	$/mile	1,800,000
Roads	$/mile	250,000
Note: 1. Costs presented are specific to a combined cycle project and do not include any interconnection costs.		

Expected project durations for activities starting with development of the EPC specification through the commercial operation date (COD) of the power plant are presented in Table 5-4. Activities not included in the expected project duration include permitting and other activities required prior to EPC specification development. A typical duration for EPC specification development, bidding, negotiation, and award is 7 to 10 months. Incremental cash flows are also presented in Table 5-4. Cash flows are expressed as a percentage of the overnight EPC Cost portion spent during the Expected Project Duration, from EPC award to COD. For example, for the 1x1 GE 7F.05 option, the project has an expected duration of 36 months, and the EPC contractor is expected to expend 62 percent of budget at the end of the 3/6 portion of the project, which is the project mid-way point, 18 months into the project.

Table 5-4 Project Durations and Expenditure Patterns for SSOs

ID	OPTION	EPC SPEC DEVELOPMENT TO CONTRACT AWARD(1) (MONTHS)	EXPECTED PROJECT DURATION(2) (MONTHS)	INCREMENTAL CASH FLOWS(3) (1/6, 2/6, 3/6, 4/6, 5/6, 6/6)
CC-A	1x1 GE 7F.05	7 to 10	36	10, 20, 32, 23, 13, 2
CC-B	1x1 GE 7HA.01	7 to 10	36	10, 20, 32, 23, 13, 2
PP-A	3x0 Wartsila 18V50SG	7 to 10	24	14, 25, 33, 19, 7, 2
PP-B	6x0 Wartsila 18V50SG	7 to 10	24	14, 25, 33, 19, 7, 2
PP-C	12x0 Wartsila 18V50SG	7 to 10	24	14, 25, 33, 19, 7, 2
PP-D	1x0 GE LMS100PA+	7 to 10	28	14, 25, 33, 19, 7, 2
PP-E	2x0 GE LMS100PA+	7 to 10	28	14, 25, 33, 19, 7, 2
PP-F	1x0 GE 7F.05	7 to 10	28	14, 25, 33, 19, 7, 2

Notes:
1. Permitting and other activities required prior to EPC specification development are not included in EPC Spec Development to Contract Award period.
2. Expected Contract Duration represents the number of months from EPC contract award to COD.
3. Incremental Cash Flows represent the percentage of total capital cost expended across six time increments between EPC contract award to COD.

5.2 NON-FUEL O&M COST ESTIMATES

Estimates of O&M costs for Greenfield options are presented in Table 5-5. Variations in O&M costs for projects sited at brownfield locations are discussed in Appendix E.

Table 5-5 Summary of O&M Cost Estimates (for Greenfield Options)

ID	OPTION	AVERAGE DAY NET OUTPUT(1) (MW)	ANNUAL CAPACITY FACTOR (%)	ANNUAL NUMBER OF STARTS	ANNUAL NET GENERATION (MWh)	ANNUAL FIXED O&M		ANNUAL VARIABLE O&M	
						($000)	($/kW-yr)	($000)	($/MWh)
CC-A	1x1 GE 7F.05	359.1	80	70	2,517,000	2,915	8.1	6,270	2.5
CC-B	1x1 GE 7HA.01	405.1	80	70	2,839,000	2,970	7.3	6,750	2.4
PP-A	3x0 Wartsila 18V50SG	55.5	5	100	24,300	1,340	24.1	210	8.6
PP-B	6x0 Wartsila 18V50SG	111.0	5	100	48,600	1,420	12.8	390	8.0
PP-C	12x0 Wartsila 18V50SG	222.0	5	100	97,200	1,940	8.7	760	7.8
PP-D	1x0 GE LMS100PA+	113.7	6	100	59,800	1,390	12.2	610	10.2
PP-E	2x0 GE LMS100PA+	227.3	6	100	119,500	1,480	6.5	1,210	10.1
PP-F	1x0 GE 7F.05	239.0	2	100	41,900	1,540	6.4	965	23.0

Notes:

1. Average day net output based on ambient conditions of 51°F and relative humidity of 75%.

For purposes of bidding into certain power markets, Variable O&M (VOM) costs may be required to be provided as follows:

- Operations (including chemicals and consumables), in terms of $/MWh
- Corrective maintenance, in terms of $/MWh
- Major maintenance, in terms of $/hour (for combined cycle units) or $/start (for peaking units)

Based on the estimates of non-fuel O&M costs listed in Table 5-5, Black & Veatch has developed a breakout of VOM as shown in Table 5-6.

Table 5-6 Breakout of Annual Non-fuel Variable O&M Costs

ID	OPTION	OPERATIONS COSTS(1)		CORRECTIVE MAINT. COSTS	MAJOR MAINTENANCE COSTS(3)		
		($000)	($/MWh)		($000)	($/hr)	($/start)
CC-A	1x1 GE 7F.05	2,350	0.93	Note (2)	3,915	560	n/a
CC-B	1x1 GE 7HA.01	2,650	0.93		4,095	580	n/a
PP-A	3x0 Wartsila 18V50SG	50	2.06		155	350	n/a
PP-B	6x0 Wartsila 18V50SG	80	1.65		310	710	n/a
PP-C	12x0 Wartsila 18V50SG	140	1.44		625	1,430	n/a
PP-D	1x0 GE LMS100PA+	170	2.81		445	850	n/a
PP-E	2x0 GE LMS100PA+	315	2.61		890	1,690	n/a
PP-F	1x0 GE 7F.05	40	0.95		925	n/a	9,250

Notes:

1. Operations Costs include chemicals and consumables but do not include fuel.
2. Corrective Maintenance Costs are assumed to be primarily associated with unscheduled maintenance costs or maintenance costs associated with forced outages. These costs are included within Black & Veatch estimates of Major Maintenance Costs, but are not distinguished within Major Maintenance Costs.
3. Major Maintenance Costs include scheduled and/or forced outage maintenance and costs associated with Long Term Service Agreements (LTSAs).

Periodically, power generation units must be taken offline to perform inspections and potentially replace worn components. Maintenance intervals recommended by the Original Equipment Manufacturer (OEM) for these inspections and corresponding maintenance provide an indication of operational reliability of the units. Manufacturer-recommended maintenance intervals for each SSO are presented in Table 5-7. Wartsila recommended maintenance activities were provided by the manufacturer and are included in Appendix G of this document. For the combined cycle options, it is anticipated that major maintenance activities for the steam turbine and other plant equipment would be scheduled during CTG maintenance outages to minimize impacts to plant availability.

Table 5-7 CTG/RICE Manufacturer Recommended Maintenance Intervals

ID	OPTION	COMBUSTION INSPECTION	HOT GAS PATH INSPECTION(1)	MAJOR INSPECTION(2)
CC-A	1x1 GE 7F.05	16,000 FFH/ 1,250 FS	32,000 FFH/ 1,250 FS	64,000 FFH/ 2,500 FS
CC-B	1x1 GE 7HA.01	n/a	25,000 FFH/ 900 FS	50,000 FFH/ 1,800 FS
PP-A	3x0 Wartsila 18V50SG	See Appendix D		
PP-B	6x0 Wartsila 18V50SG			
PP-C	12x0 Wartsila 18V50SG			
PP-D	1x0 GE LMS100PA+	n/a	25,000 AFH	50,000 AFH
PP-E	2x0 GE LMS100PA+	n/a	25,000 AFH	50,000 AFH
PP-F	1x0 GE 7F.05	16,000 FFH/ 1,250 FS	32,000 FFH/ 1,250 FS	64,000 FFH/ 2,500 FS

Abbreviations:

AFH: Actual Fired Hours
FFH: Factored Fired Hour
FS: Factored Starts

Notes:

1. Hot Gas Path Inspection scope of work includes Combustion Inspection scope of work.
2. Major Inspections scope of work includes Hot Gas Path Inspection scope of work.

Appendix A. Full Thermal Performance Estimates for Supply-Side Options

Puget Sound Energy
B&V Project Number 192143
1x1 GE 7F.05
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% CTG Load	23 deg F 75% CTG Load	23 deg F MECL	51 deg F 100% CTG Load	51 deg F 75% CTG Load	51 deg F MECL	ISO Conditions 100% CTG Load	ISO Conditions 75% CTG Load	ISO Conditions MECL	88 deg F 100% CTG Load	88 deg F 75% CTG Load	88 deg F MECL
CTG Configuration	-	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1
Heat Rejection System	-	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
CTG Model	-	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level	%	100	75	45	100	75	45	100	75	45	100	75	45
NEW & CLEAN PERFORMANCE													
Gross CTG Output (each)	kW	244,741	183,555	110,133	244,741	183,555	110,133	244,027	183,020	109,812	227,322	170,492	102,295
Number of Gas Turbines in Operation		1	1	1	1	1	1	1	1	1	1	1	1
Gross CTG Output	kW	244,741	183,555	110,133	244,741	183,555	110,133	244,027	183,020	109,812	227,322	170,492	102,295
Gross Steam Turbine Output	kW	114,823	95,629	83,207	123,542	98,853	84,156	125,397	99,570	84,297	122,118	98,137	82,836
CTG Heat Input (LHV) (each)	MBtu/h	2,095	1,637	1,229	2,111	1,639	1,214	2,110	1,636	1,209	1,989	1,555	1,161
CTG Heat Input (HHV) (each)	MBtu/h	2,324	1,816	1,363	2,342	1,819	1,347	2,341	1,816	1,341	2,207	1,725	1,288
Total Plant Auxiliary Power	kW	8,910	7,776	6,711	9,166	8,134	7,032	9,181	8,136	7,190	8,934	7,974	7,072
NET PLANT PERFORMANCE													
Net Plant Output	kW	350,654	271,408	186,629	359,116	274,275	187,257	360,243	274,454	186,920	340,505	260,655	178,059
Net Plant Heat Rate (LHV)	Btu/kWh	5,974	6,031	6,583	5,877	5,977	6,484	5,857	5,962	6,466	5,842	5,965	6,520
Net Plant Heat Rate (HHV)	Btu/kWh	6,629	6,692	7,305	6,522	6,632	7,195	6,499	6,616	7,175	6,483	6,619	7,235
Net Plant Efficiency (LHV)	%	57.1%	56.6%	51.8%	58.1%	57.1%	52.6%	58.3%	57.2%	52.8%	58.4%	57.2%	52.3%
Net Plant Efficiency (HHV)	%	51.5%	51.0%	46.7%	52.3%	51.5%	47.4%	52.5%	51.6%	47.6%	52.6%	51.6%	47.2%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	2	2	2	2	2	2	2	2	2	2	2	2
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072
	lb/hr	16.7	13	9.8	16.8	13.1	9.7	16.8	13	9.6	15.9	12.4	9.3
CO	ppmvd @ 15% O2	2	2	2	2	2	2	2	2	2	2	2	2
	lb/MBtu (HHV)	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044
	lb/hr	10.2	7.9	6	10.2	8	5.9	10.2	7.9	5.9	9.7	7.5	5.6
CO2	lb/hr	267,277	208,866	156,766	269,307	209,168	154,928	269,224	208,784	154,215	253,806	198,386	148,124
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	940	762	692	1,152	906	766	1,239	985	831	1,488	1,248	1,095
Steam Cycle Makeup Water (2% of Flow)	GPM	27	22	18	28	22	18	28	23	18	28	22	18
CTG Water Injection	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

1) PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.
2) CTG performance is based on data from GTP Web from May 2016
3) The fuel gas is unheated and is assumed to be supplied at 80 F
4) No inlet conditioning applied
5) No HRSG duct firing applied.
6) HRSG, STG and Heat Rejection System sized using GT Pro software
7) STG Last Stage Blade geometry selected by GT Pro software.
8) Condenser Pressure designed to be 1.88 inches HgA at design (88 F) conditions
9) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
10) Emission flowrate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PPM rates provided by GE
11) SCR designed to reduce stack NOx to 2.0 ppmvd @15% O2

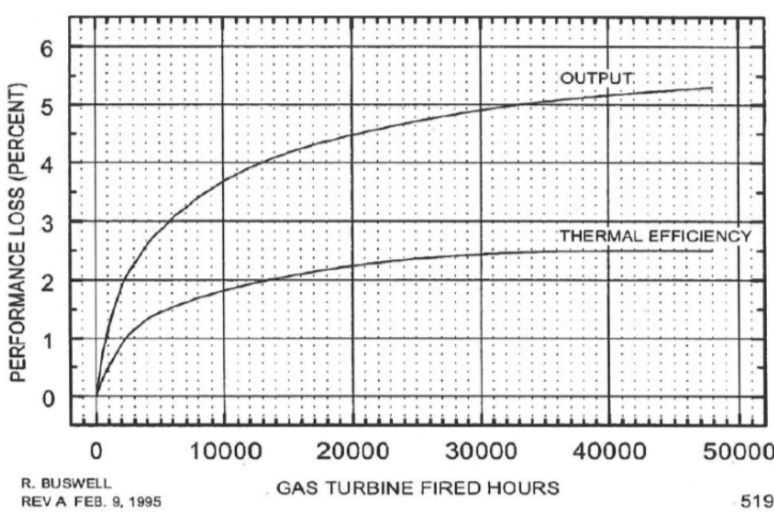
Puget Sound Energy
B&V Project Number 192143
1x1 7F.05 Degradation Curve

GE Power Systems

EXPECTED GAS TURBINE PLANT PERFORMANCE LOSS FOLLOWING NORMAL MAINTENANCE AND OFF-LINE COMPRESSOR WATER WASH

THE AGED PERFORMANCE EFFECTS REPRESENTED BY THESE CURVES ARE BASED ON THE FOLLOWING:

- PERFORMANCE IS RELATIVE TO THE GUARANTEE LEVEL.
- ALL GAS TURBINE PLANT EQUIPMENT SHALL BE OPERATED AND MAINTAINED IN ACCORDANCE WITH GE'S RECOMMENDED PROCEDURES FOR OPERATION, PREVENTIVE MAINTENANCE, INSPECTION AND BOTH ON-LINE AND OFF-LINE CLEANING.
- ALL OPERATIONS SHALL BE WITHIN THE DESIGN CONDITIONS SPECIFIED IN THE RELEVANT TECHNICAL SPECIFICATIONS.
- A DETAILED OPERATIONAL LOG SHALL BE MAINTAINED FOR ALL RELEVANT OPERATIONAL DATA, TO BE AGREED TO AMONGST THE PARTIES PRIOR TO COMMENCEMENT OF CONTRACT.
- GE TECHNICAL PERSONNEL SHALL HAVE ACCESS TO PLANT OPERATIONAL DATA, LOGS, AND SITE VISITS PRIOR TO CONDUCTING A PERFORMANCE TEST. THE OWNER WILL CLEAN AND MAINTAIN THE EQUIPMENT. THE DEGREE OF CLEANING AND MAINTENANCE WILL BE DETERMINED BASED ON THE OPERATING HISTORY OF EACH UNIT, ATMOSPHERIC CONDITIONS EXPERIENCED DURING THE PERIOD OF OPERATION, THE PREVENTIVE AND SCHEDULED MAINTENANCE PROGRAMS EXECUTED, AND THE RESULTS OF THE GE INSPECTION.
- THE GAS TURBINE WILL BE SHUT DOWN FOR INSPECTION AND OFF-LINE COMPRESSOR WATER WASH, AS A MINIMUM, IMMEDIATELY PRIOR TO PERFORMANCE TESTING TO DETERMINE PERFORMANCE LOSS. THE GAS TURBINE PERFORMANCE TEST SHALL OCCUR WITHIN 100 FIRED HOURS OF THESE ACTIONS.
- DEMONSTRATION OF GAS TURBINE PLANT PERFORMANCE SHALL BE IN ACCORDANCE WITH TEST PROCEDURES WHICH ARE MUTUALLY AGREED UPON.



R. BUSWELL
REV A FEB. 9, 1995

519HA772

Notes:

1. Degradation curves based on generic GE 7FA data from 2/9/1995.

Puget Sound Energy **B&V Project Number 192143** **1x1 GE 7HA.01** **Preliminary Performance Summary** **May 27, 2016 - Rev A**													
Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% CTG Load	23 deg F 75% CTG Load	23 deg F MECL	51 deg F 100% CTG Load	51 deg F 75% CTG Load	51 deg F MECL	ISO Conditions 100% CTG Load	ISO Conditions 75% CTG Load	ISO Conditions MECL	88 deg F 100% CTG Load	88 deg F 75% CTG Load	88 deg F MECL
CTG Configuration	-	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1
Heat Rejection System	-	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower	Mech. Cooling Tower
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
CTG Model	-	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level	%	100	75	34	100	75	36	100	75	34	100	75	30
NEW & CLEAN PERFORMANCE													
Gross CTG Output (each)	kW	289,135	216,851	98,306	285,100	213,825	102,636	281,301	210,976	95,642	252,668	189,501	75,800
Number of Gas Turbines in Operation		1	1	1	1	1	1	1	1	1	1	1	1
Gross CTG Output	kW	289,135	216,851	98,306	285,100	213,825	102,636	281,301	210,976	95,642	252,668	189,501	75,800
Gross STG Output	kW	124,782	106,233	77,127	131,063	109,045	78,832	130,936	108,915	76,876	126,419	103,635	71,675
CTG Heat Input (LHV) (each)	MBtu/h	2,355	1,858	1,136	2,340	1,842	1,147	2,309	1,823	1,100	2,117	1,678	967
CTG Heat Input (HHV) (each)	MBtu/h	2,613	2,061	1,261	2,596	2,044	1,272	2,563	2,023	1,221	2,349	1,862	1,073
Total Plant Auxiliary Power	kW	10,874	9,470	7,424	11,048	9,798	7,817	10,987	9,755	7,699	10,525	9,380	7,533
NET PLANT PERFORMANCE													
Net Plant Output	kW	403,042	313,614	168,009	405,115	313,072	173,652	401,250	310,136	164,820	368,562	283,755	139,943
Net Plant Heat Rate (LHV)	Btu/kWh	5,843	5,924	6,763	5,776	5,883	6,603	5,756	5,878	6,675	5,745	5,912	6,910
Net Plant Heat Rate (HHV)	Btu/kWh	6,484	6,573	7,505	6,409	6,527	7,326	6,387	6,522	7,407	6,375	6,560	7,668
Net Plant Efficiency (LHV)	%	58.4%	57.6%	50.5%	59.1%	58.0%	51.7%	59.3%	58.1%	51.1%	59.4%	57.7%	49.4%
Net Plant Efficiency (HHV)	%	52.6%	51.9%	45.5%	53.3%	52.3%	46.6%	53.4%	52.3%	46.1%	53.5%	52.0%	44.5%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	2	2	2	2	2	2	2	2	2	2	2	2
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072
	lb/hr	18.8	14.8	9.1	18.7	14.7	9.2	18.5	14.6	8.8	16.9	13.4	7.7
CO	ppmvd @ 15% O2	2	2	2	2	2	2	2	2	2	2	2	2
	lb/MBtu (HHV)	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044
	lb/hr	11.5	9.1	5.5	11.4	9.0	5.6	11.3	8.9	5.4	10.3	8.2	4.7
CO2	lb/hr	300,486	237,040	144,988	298,548	234,987	146,293	294,677	232,583	140,376	270,163	214,059	123,391
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	1,038	858	632	1,246	1,002	722	1,318	1,078	772	1,546	1,320	1,004
Steam Cycle Makeup Water (2% of Flow)	GPM	30	24	17	31	25	18	30	25	17	29	24	16
CTG Water Injection	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

1) **PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.**
2) CTG performance is based on data from GTP Web from May 2016
3) The fuel gas is unheated and is assumed to be supplied at 8(F.
4) No inlet conditioning applied
5) No HRSG duct firing applied.
6) HRSG, STG and Heat Rejection System sized using GT Pro software
7) STG Last Stage Blade geometry selected by GT Pro software.
8) Condenser Pressure designed to be 1.88 inches HgA at design (8(F) conditions.
9) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
10) Emission flowrate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PPM rates provided by GE
11) SCR designed to reduce stack NOx to 2.0 ppmvd @15% O2

Puget Sound Energy
B&V Project Number 192143
3x Wartsila 18V50SG
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% RICE Load	23 deg F 75% RICE Load	23 deg F MECL	51 deg F 100% RICE Load	51 deg F 75% RICE Load	51 deg F MECL	ISO Conditions 100% RICE Load	ISO Conditions 75% RICE Load	ISO Conditions MECL	88 deg F 100% RICE Load	88 deg F 75% RICE Load	88 deg F MECL
RICE Configuration	-	3x0	3x0	3x0	3x0	3x0	3x0	3x0	3x0	3x0	3x0	3x0	3x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
Reciprocating Engine Model	-	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG
Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Load Level	%	100	75	25	100	75	25	100	75	25	100	75	25
NEW & CLEAN PERFORMANCE													
Gross RICE Output (each)	kW	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621
Number of Engines in Operation		3	3	3	3	3	3	3	3	3	3	3	3
Gross RICE Output	kW	56,451	42,354	13,863	56,451	42,354	13,863	56,451	42,354	13,863	56,451	42,354	13,863
RICE Heat Input (LHV) (each)	MBtu/h	137.6	108.0	43.0	137.6	108.0	43.0	137.6	108.0	43.0	137.6	108.0	43.0
RICE Heat Input (HHV) (each)	MBtu/h	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7
Total Plant Auxiliary Power	kW	847	741	485	960	741	485	1,016	805	499	1,242	1,059	527
NET PLANT PERFORMANCE													
Net Plant Output	kW	55,604	41,613	13,378	55,491	41,613	13,378	55,435	41,549	13,364	55,209	41,295	13,336
Net Plant Heat Rate (LHV)	Btu/kWh	7,425	7,785	9,650	7,440	7,785	9,650	7,448	7,797	9,660	7,479	7,845	9,680
Net Plant Heat Rate (HHV)	Btu/kWh	8,239	8,639	10,707	8,256	8,639	10,707	8,264	8,652	10,719	8,298	8,705	10,741
Net Plant Efficiency (LHV)	%	46.0%	43.8%	35.4%	45.9%	43.8%	35.4%	45.8%	43.8%	35.3%	45.6%	43.5%	35.3%
Net Plant Efficiency (HHV)	%	41.4%	39.5%	31.9%	41.3%	39.5%	31.9%	41.3%	39.4%	31.8%	41.1%	39.2%	31.8%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0
	lb/MBtu (HHV)	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015
	lb/hr	2.49	2.18	0.71	2.49	2.18	0.71	2.49	2.18	0.71	2.49	2.18	0.71
CO	ppmvd @ 15% O2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	lb/MBtu (HHV)	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043
	lb/hr	4.97	4.35	2.03	4.97	4.35	2.03	4.97	4.35	2.03	4.97	4.35	2.03
CO2	lb/hr	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Steam Cycle Makeup Water (2% of Flow)	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Engine Water Injection	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

1) PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.
2) Engine performance is based on data obtained from Wartsila in April 2016
3) The fuel gas is unheated and is assumed to be supplied at 80° F.
4) No inlet conditioning applied
5) Auxiliary power estimate assumes a 3-engine power block.
6) SCR designed to reduce stack NOx to 5.0 ppmvd @15% O2 at full load
7) Wartsila engines assumed to employ air-cooled radiators for heat rejection

Puget Sound Energy
B&V Project Number 192143
6x Wartsila 18V50SG
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% RICE Load	23 deg F 75% RICE Load	23 deg F MECL	51 deg F 100% RICE Load	51 deg F 75% RICE Load	51 deg F MECL	ISO Conditions 100% RICE Load	ISO Conditions 75% RICE Load	ISO Conditions MECL	88 deg F 100% RICE Load	88 deg F 75% RICE Load	88 deg F MECL
RICE Configuration	-	6x0	6x0	6x0	6x0	6x0	6x0	6x0	6x0	6x0	6x0	6x0	6x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
Reciprocating Engine Model	-	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG
Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Load Level	%	100	75	25	100	75	25	100	75	25	100	75	25
NEW & CLEAN PERFORMANCE													
Gross RICE Output (each)	kW	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621
Number of Engines in Operation		6	6	6	6	6	6	6	6	6	6	6	6
Gross RICE Output	kW	112,902	84,708	27,726	112,902	84,708	27,726	112,902	84,708	27,726	112,902	84,708	27,726
RICE Heat Input (LHV) (each)	MBtu/h	137.6	108.0	43.0	137.6	108.0	43.0	137.6	108.0	43.0	137.6	108.0	43.0
RICE Heat Input (HHV) (each)	MBtu/h	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7
Total Plant Auxiliary Power	kW	1,694	1,482	970	1,919	1,482	970	2,032	1,609	998	2,484	2,118	1,054
NET PLANT PERFORMANCE													
Net Plant Output	kW	111,208	83,226	26,756	110,983	83,226	26,756	110,870	83,099	26,728	110,418	82,590	26,672
Net Plant Heat Rate (LHV)	Btu/kWh	7,425	7,785	9,650	7,440	7,785	9,650	7,448	7,797	9,660	7,479	7,845	9,680
Net Plant Heat Rate (HHV)	Btu/kWh	8,239	8,639	10,707	8,256	8,639	10,707	8,264	8,652	10,719	8,298	8,705	10,741
Net Plant Efficiency (LHV)	%	46.0%	43.8%	35.4%	45.9%	43.8%	35.4%	45.8%	43.8%	35.3%	45.6%	43.5%	35.3%
Net Plant Efficiency (HHV)	%	41.4%	39.5%	31.9%	41.3%	39.5%	31.9%	41.3%	39.4%	31.8%	41.1%	39.2%	31.8%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0
	lb/MBtu (HHV)	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015
	lb/hr	2.49	2.18	0.71	2.49	2.18	0.71	2.49	2.18	0.71	2.49	2.18	0.71
CO	ppmvd @ 15% O2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	lb/MBtu (HHV)	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043
	lb/hr	4.97	4.35	2.03	4.97	4.35	2.03	4.97	4.35	2.03	4.97	4.35	2.03
CO2	lb/hr	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Steam Cycle Makeup Water (2% of Flow)	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Engine Water Injection	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

1) **PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.**
2) Engine performance is based on data obtained from Wartsila in April 2016
3) The fuel gas is unheated and is assumed to be supplied at 80° F.
4) No inlet conditioning applied.
5) Auxiliary power estimate assumes a 3-engine power block.
6) SCR designed to reduce stack NOx to 5.0 ppmvd @15% O2 at full load
7) Wartsila engines assumed to employ air-cooled radiators for heat rejection

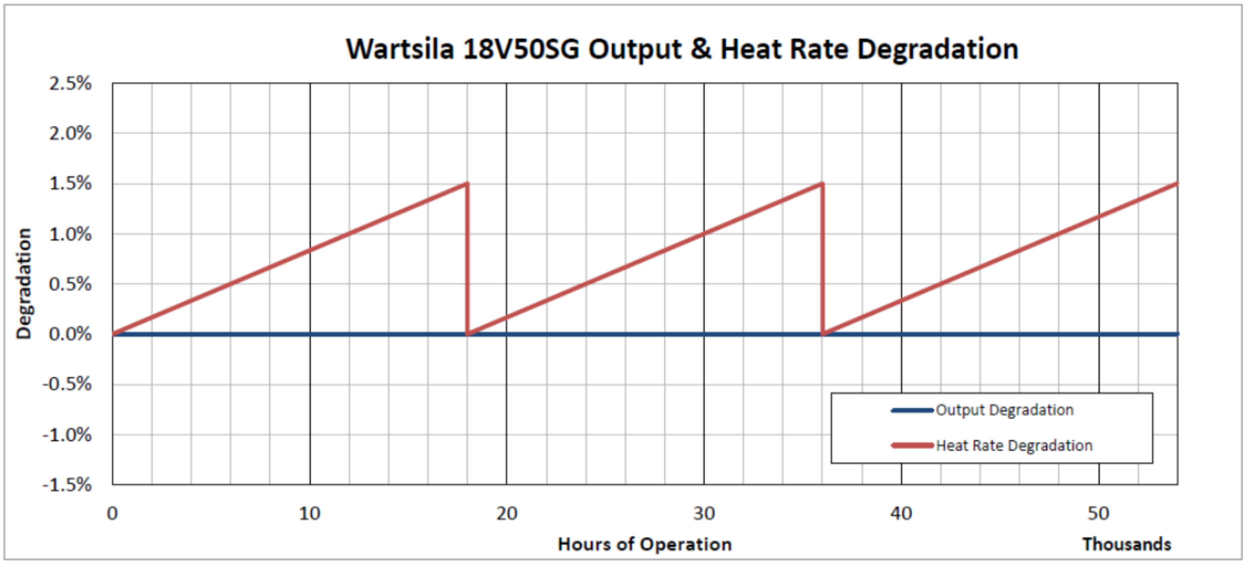
Puget Sound Energy
B&V Project Number 192143
12x Wartsila 18V50SG
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% RICE Load	23 deg F 75% RICE Load	23 deg F MECL	51 deg F 100% RICE Load	51 deg F 75% RICE Load	51 deg F MECL	ISO Conditions 100% RICE Load	ISO Conditions 75% RICE Load	ISO Conditions MECL	88 deg F 100% RICE Load	88 deg F 75% RICE Load	88 deg F MECL
RICE Configuration	-	12x0	12x0	12x0	12x0	12x0	12x0	12x0	12x0	12x0	12x0	12x0	12x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
Reciprocating Engine Model	-	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG
Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Load Level	%	100	75	25	100	75	25	100	75	25	100	75	25
NEW & CLEAN PERFORMANCE													
Gross RICE Output (each)	kW	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621
Number of Engines in Operation		12	12	12	12	12	12	12	12	12	12	12	12
Gross RICE Output	kW	225,804	169,416	55,452	225,804	169,416	55,452	225,804	169,416	55,452	225,804	169,416	55,452
RICE Heat Input (LHV) (each)	MBtu/h	137.6	108.0	43.0	137.6	108.0	43.0	137.6	108.0	43.0	137.6	108.0	43.0
RICE Heat Input (HHV) (each)	MBtu/h	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7
Total Plant Auxiliary Power	kW	3,387	2,965	1,941	3,839	2,965	1,941	4,064	3,219	1,996	4,968	4,235	2,107
NET PLANT PERFORMANCE													
Net Plant Output	kW	222,417	166,451	53,511	221,965	166,451	53,511	221,740	166,197	53,456	220,836	165,181	53,345
Net Plant Heat Rate (LHV)	Btu/kWh	7,425	7,785	9,650	7,440	7,785	9,650	7,448	7,797	9,660	7,479	7,845	9,680
Net Plant Heat Rate (HHV)	Btu/kWh	8,239	8,639	10,707	8,256	8,639	10,707	8,264	8,652	10,719	8,298	8,705	10,741
Net Plant Efficiency (LHV)	%	46.0%	43.8%	35.4%	45.9%	43.8%	35.4%	45.8%	43.8%	35.3%	45.6%	43.5%	35.3%
Net Plant Efficiency (HHV)	%	41.4%	39.5%	31.9%	41.3%	39.5%	31.9%	41.3%	39.4%	31.8%	41.1%	39.2%	31.8%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0
	lb/MBtu (HHV)	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015
	lb/hr	2.49	2.18	0.71	2.49	2.18	0.71	2.49	2.18	0.71	2.49	2.18	0.71
CO	ppmvd @ 15% O2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	lb/MBtu (HHV)	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043
	lb/hr	4.97	4.35	2.03	4.97	4.35	2.03	4.97	4.35	2.03	4.97	4.35	2.03
CO2	lb/hr	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Steam Cycle Makeup Water (2% of Flow)	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Engine Water Injection	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

#DIV/0!

1) PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.
2) Engine performance is based on data obtained from Wartsila in April 2016.
3) The fuel gas is unheated and is assumed to be supplied at 80° F.
4) No inlet conditioning applied.
5) Auxiliary power estimate assumes a 3-engine power block.
6) SCR designed to reduce stack NOx to 5.0 ppmvd @15% O2 at full load.
7) Wartsila engines assumed to employ air-cooled radiators for heat rejection.

Puget Sound Energy
B&V Project Number 192143
Wartsila 18V50SG Degradation Curve



Notes:

1. Degradation curves based on e-mail from Wartsila on 11/7/2012.

Puget Sound Energy
B&V Project Number 192143
1x GE LMS100PA+
Preliminary Performance Summary
May 27, 2016 - Rev A

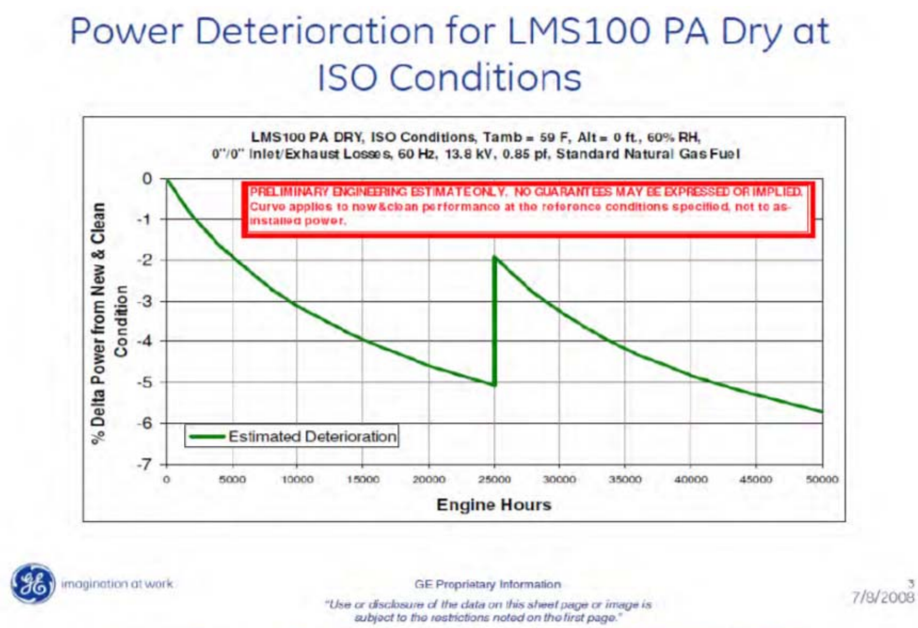
Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% CTG Load	23 deg F 75% CTG Load	23 deg F MECL	51 deg F 100% CTG Load	51 deg F 75% CTG Load	51 deg F MECL	ISO Conditions 100% CTG Load	ISO Conditions 75% CTG Load	ISO Conditions MECL	88 deg F 100% CTG Load	88 deg F 75% CTG Load	88 deg F MECL
CTG Configuration	-	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
CTG Model	-	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level	%	100	75	25	100	75	25	100	75	25	100	75	25
NEW & CLEAN PERFORMANCE													
Gross CTG Output (each)	kW	114,920	86,191	28,730	116,508	87,380	29,127	117,000	87,750	29,250	112,423	84,316	28,108
Number of Gas Turbines in Operation		1	1	1	1	1	1	1	1	1	1	1	1
Gross CTG Output	kW	114,920	86,191	28,730	116,508	87,380	29,127	117,000	87,750	29,250	112,423	84,316	28,108
CTG Heat Input (LHV) (each)	MBtu/h	887	711	351	902	720	355	908	724	356	886	706	349
CTG Heat Input (HHV) (each)	MBtu/h	984	789	389	1,001	799	393	1,008	803	395	984	783	387
Total Plant Auxiliary Power	kW	2,823	2,351	1,397	2,856	2,374	1,406	2,869	2,381	1,409	2,803	2,330	1,390
NET PLANT PERFORMANCE													
Net Plant Output	kW	112,098	83,840	27,332	113,651	85,006	27,721	114,131	85,369	27,841	109,620	81,986	26,718
Net Plant Heat Rate (LHV)	Btu/kWh	7,914	8,477	12,842	7,938	8,473	12,789	7,958	8,475	12,786	8,086	8,608	13,054
Net Plant Heat Rate (HHV)	Btu/kWh	8,782	9,406	14,249	8,808	9,402	14,191	8,830	9,404	14,187	8,972	9,552	14,484
Net Plant Efficiency (LHV)	%	43.1%	40.3%	26.6%	43.0%	40.3%	26.7%	42.9%	40.3%	26.7%	42.2%	39.6%	26.1%
Net Plant Efficiency (HHV)	%	38.9%	36.3%	24.0%	38.7%	36.3%	24.1%	38.7%	36.3%	24.1%	38.0%	35.7%	23.6%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MBtu (HHV)	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
	lb/hr	8.8	7.1	3.5	9.0	7.2	3.6	9.0	7.2	3.6	8.8	7.1	3.5
CO	ppmvd @ 15% O2	6	6	6	6	6	6	6	6	6	6	6	6
	lb/MBtu (HHV)	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131
	lb/hr	12.9	10.3	5.1	13.1	10.5	5.2	13.2	10.5	5.2	12.9	10.3	5.1
CO2	lb/hr	113,201	90,675	44,787	115,109	91,896	45,233	115,884	92,313	45,412	113,083	90,049	44,488
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	175	128	40	207	157	55	215	165	60	235	184	72
Steam Cycle Makeup Water (2% of Flow)	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CTG Water Injection	GPM	58	42	15	55	39	13	56	40	13	53	37	12

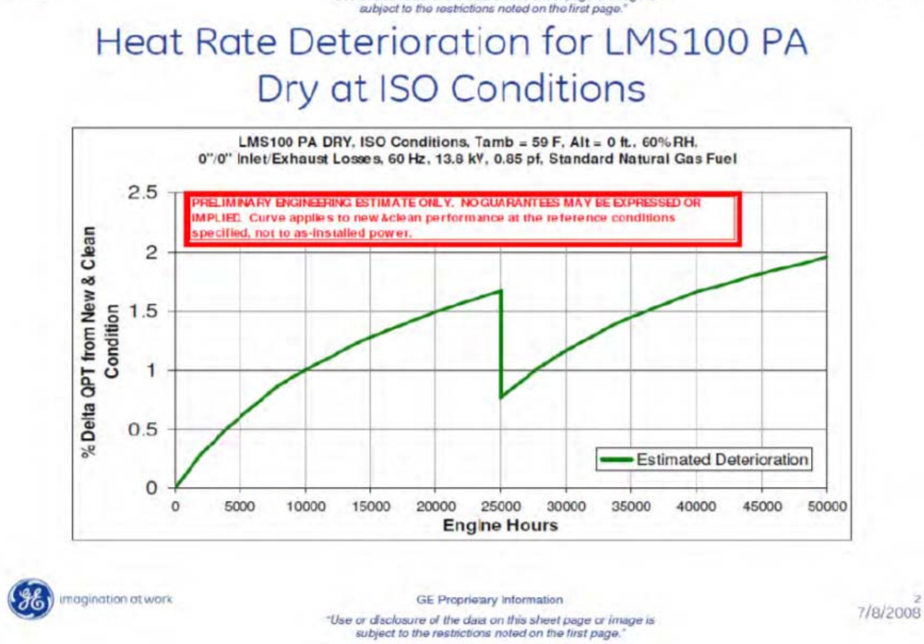
1) PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.
2) CTG performance is based on data from GE APPS from May 2016
3) Water injection to control CTG NOx to 25 ppm @15% O2
4) The fuel gas is unheated and is assumed to be supplied at 80° F.
5) The fuel supply pressure is assumed to be 400 psia at the site boundary
6) No inlet conditioning applied
7) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
8) Emission flowrate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PPM rates provided by GE
9) SCR designed to reduce stack NOx to 2.5 ppmvd @15% O2.

Puget Sound Energy													
B&V Project Number 192143													
2x GE LMS100PA+													
Preliminary Performance Summary													
May 27, 2016 - Rev A													
Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% CTG Load	23 deg F 75% CTG Load	23 deg F MECL	51 deg F 100% CTG Load	51 deg F 75% CTG Load	51 deg F MECL	ISO Conditions 100% CTG Load	ISO Conditions 75% CTG Load	ISO Conditions MECL	88 deg F 100% CTG Load	88 deg F 75% CTG Load	88 deg F MECL
CTG Configuration	-	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
CTG Model	-	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+	GE LMS100PA+
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level	%	100	75	25	100	75	25	100	75	25	100	75	25
NEW & CLEAN PERFORMANCE													
Gross CTG Output (each)	kW	114,920	86,191	28,730	116,508	87,380	29,127	117,000	87,750	29,250	112,423	84,316	28,108
Number of Gas Turbines in Operation		2	2	2	2	2	2	2	2	2	2	2	2
Gross CTG Output	kW	229,841	172,381	57,460	233,016	174,760	58,253	234,000	175,501	58,499	224,846	168,632	56,216
CTG Heat Input (LHV) (each)	MBtu/h	887	711	351	902	720	355	908	724	356	886	706	349
CTG Heat Input (HHV) (each)	MBtu/h	984	789	389	1,001	799	393	1,008	803	395	984	783	387
Total Plant Auxiliary Power	kW	5,616	4,673	2,766	5,684	4,719	2,782	5,709	4,734	2,788	5,577	4,631	2,750
NET PLANT PERFORMANCE													
Net Plant Output	kW	224,225	167,708	54,694	227,332	170,041	55,471	228,291	170,767	55,711	219,269	164,001	53,466
Net Plant Heat Rate (LHV)	Btu/kWh	7,913	8,476	12,835	7,937	8,472	12,783	7,957	8,474	12,779	8,085	8,607	13,047
Net Plant Heat Rate (HHV)	Btu/kWh	8,781	9,405	14,242	8,807	9,400	14,184	8,829	9,402	14,180	8,971	9,550	14,477
Net Plant Efficiency (LHV)	%	43.1%	40.3%	26.6%	43.0%	40.3%	26.7%	42.9%	40.3%	26.7%	42.2%	39.7%	26.2%
Net Plant Efficiency (HHV)	%	38.9%	36.3%	24.0%	38.8%	36.3%	24.1%	38.7%	36.3%	24.1%	38.0%	35.7%	23.6%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MBtu (HHV)	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
	lb/hr	8.8	7.1	3.5	9.0	7.2	3.6	9.0	7.2	3.6	8.8	7.1	3.5
CO	ppmvd @ 15% O2	6	6	6	6	6	6	6	6	6	6	6	6
	lb/MBtu (HHV)	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131
	lb/hr	12.9	10.3	5.1	13.1	10.5	5.2	13.2	10.5	5.2	12.9	10.3	5.1
CO2	lb/hr	113,201	90,675	44,787	115,109	91,896	45,233	115,884	92,313	45,412	113,083	90,049	44,488
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	175	128	40	207	157	55	215	165	60	235	184	72
Steam Cycle Makeup Water (2% of Flow)	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CTG Water Injection	GPM	58	42	15	55	39	13	56	40	13	53	37	12

1) **PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.**
2) CTG performance is based on data from GE APPS from May 2016
3) Water injection to control CTG NOx to 25 ppm @15% O2
4) The fuel gas is unheated and is assumed to be supplied at 8C° F.
5) The fuel supply pressure is assumed to be 400 psia at the site boundary
6) No inlet conditioning applied
7) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
8) Emission flowrate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PPM rates provided by GE
9) SCR designed to reduce stack NOx to 2.5 ppmvd @15% O2.

Puget Sound Energy
B&V Project Number 192143
1x0 GE LMS100PA Degradation Curve





Notes:

1. Degradation curves based on generic GE LMS100PA data from 7/8/2008.

Puget Sound Energy
B&V Project Number 192143
1x GE 7F.05
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% CTG Load	23 deg F 75% CTG Load	23 deg F MECL	51 deg F 100% CTG Load	51 deg F 75% CTG Load	51 deg F MECL	ISO Conditions 100% CTG Load	ISO Conditions 75% CTG Load	ISO Conditions MECL	88 deg F 100% CTG Load	88 deg F 75% CTG Load	88 deg F MECL
CTG Configuration	-	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
CTG Model	-	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level	%	100	75	45	100	75	45	100	75	45	100	75	45
NEW & CLEAN PERFORMANCE													
Gross CTG Output (each)	kW	244,740	183,555	110,133	242,391	181,793	109,076	240,860	180,645	108,387	227,576	170,682	102,409
Number of Gas Turbines in Operation		1	1	1	1	1	1	1	1	1	1	1	1
Gross CTG Output	kW	244,740	183,555	110,133	242,391	181,793	109,076	240,860	180,645	108,387	227,576	170,682	102,409
CTG Heat Input (LHV) (each)	MBtu/h	2,079	1,626	1,221	2,074	1,617	1,202	2,066	1,610	1,195	1,988	1,546	1,153
CTG Heat Input (HHV) (each)	MBtu/h	2,306	1,804	1,355	2,301	1,794	1,333	2,292	1,786	1,326	2,206	1,715	1,280
Total Plant Auxiliary Power	kW	3,430	2,971	2,420	3,412	2,957	2,412	3,400	2,949	2,407	3,301	2,874	2,362
NET PLANT PERFORMANCE													
Net Plant Output	kW	241,311	180,584	107,713	238,979	178,836	106,664	237,460	177,696	105,980	224,275	167,808	100,047
Net Plant Heat Rate (LHV)	Btu/kWh	8,614	9,005	11,333	8,679	9,040	11,266	8,700	9,058	11,274	8,866	9,210	11,527
Net Plant Heat Rate (HHV)	Btu/kWh	9,558	9,992	12,575	9,631	10,031	12,501	9,653	10,051	12,510	9,837	10,220	12,790
Net Plant Efficiency (LHV)	%	39.6%	37.9%	30.1%	39.3%	37.8%	30.3%	39.2%	37.7%	30.3%	38.5%	37.1%	29.6%
Net Plant Efficiency (HHV)	%	35.7%	34.2%	27.1%	35.4%	34.0%	27.3%	35.4%	34.0%	27.3%	34.7%	33.4%	26.7%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MBtu (HHV)	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
	lb/hr	20.7	16.2	12.2	20.7	16.1	12	20.6	16	11.9	19.8	15.4	11.5
CO	ppmvd @ 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MBtu (HHV)	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055
	lb/hr	12.6	9.9	7.4	12.6	9.8	7.3	12.5	9.8	7.2	12.1	9.4	7
CO2	lb/hr	265,219	207,467	155,751	264,643	206,260	153,337	263,573	205,355	152,459	253,696	197,206	147,137
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Steam Cycle Makeup Water (2% of Flow)	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CTG Water Injection	GPM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

1) PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.
2) CTG performance is based on data from GTP Web from May 2016
3) The fuel gas is unheated and is assumed to be supplied at 80° F.
5) The fuel supply pressure is assumed to be 400 psia at the site boundary
6) No inlet conditioning applied
7) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
8) Emission flowrate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PPM rates provided by GE
9) SCR designed to reduce stack NOx to 2.5 ppmvd @15% O2.

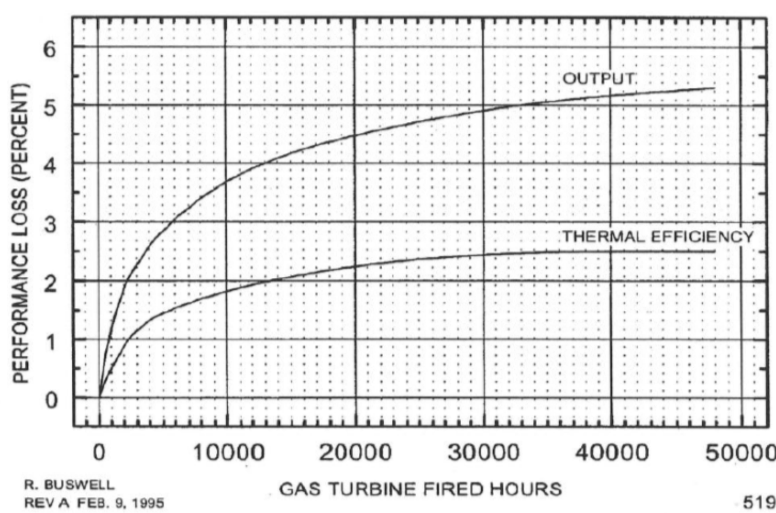
Puget Sound Energy
B&V Project Number 192143
1x0 GE 7F.05 Degradation Curve

GE Power Systems

EXPECTED GAS TURBINE PLANT PERFORMANCE LOSS FOLLOWING NORMAL MAINTENANCE AND OFF-LINE COMPRESSOR WATER WASH

THE AGED PERFORMANCE EFFECTS REPRESENTED BY THESE CURVES ARE BASED ON THE FOLLOWING:

- PERFORMANCE IS RELATIVE TO THE GUARANTEE LEVEL.
- ALL GAS TURBINE PLANT EQUIPMENT SHALL BE OPERATED AND MAINTAINED IN ACCORDANCE WITH GE'S RECOMMENDED PROCEDURES FOR OPERATION, PREVENTIVE MAINTENANCE, INSPECTION AND BOTH ON-LINE AND OFF-LINE CLEANING.
- ALL OPERATIONS SHALL BE WITHIN THE DESIGN CONDITIONS SPECIFIED IN THE RELEVANT TECHNICAL SPECIFICATIONS.
- A DETAILED OPERATIONAL LOG SHALL BE MAINTAINED FOR ALL RELEVANT OPERATIONAL DATA, TO BE AGREED TO AMONGST THE PARTIES PRIOR TO COMMENCEMENT OF CONTRACT.
- GE TECHNICAL PERSONNEL SHALL HAVE ACCESS TO PLANT OPERATIONAL DATA, LOGS, AND SITE VISITS PRIOR TO CONDUCTING A PERFORMANCE TEST. THE OWNER WILL CLEAN AND MAINTAIN THE EQUIPMENT. THE DEGREE OF CLEANING AND MAINTENANCE WILL BE DETERMINED BASED ON THE OPERATING HISTORY OF EACH UNIT, ATMOSPHERIC CONDITIONS EXPERIENCED DURING THE PERIOD OF OPERATION, THE PREVENTIVE AND SCHEDULED MAINTENANCE PROGRAMS EXECUTED, AND THE RESULTS OF THE GE INSPECTION.
- THE GAS TURBINE WILL BE SHUT DOWN FOR INSPECTION AND OFF-LINE COMPRESSOR WATER WASH, AS A MINIMUM, IMMEDIATELY PRIOR TO PERFORMANCE TESTING TO DETERMINE PERFORMANCE LOSS. THE GAS TURBINE PERFORMANCE TEST SHALL OCCUR WITHIN 100 FIRED HOURS OF THESE ACTIONS.
- DEMONSTRATION OF GAS TURBINE PLANT PERFORMANCE SHALL BE IN ACCORDANCE WITH TEST PROCEDURES WHICH ARE MUTUALLY AGREED UPON.



R. BUSWELL
REV A FEB. 9, 1995

519HA772

Notes:

1. Degradation curves based on generic GE 7FA data from 2/9/1995.

Appendix B. Air-Cooled Design Considerations

Combined cycle power plants and some peaking power plants require large heat rejection systems for proper operation. For a combined cycle power plant with adequate water supply and water discharge capacity, the combination of a surface condenser and wet mechanical draft cooling tower is the most common method of rejecting heat from a steam bottoming cycle to atmosphere. This method of heat rejection allows for a low steam turbine exhaust pressure and temperature, which results in a greater thermal efficiency of the bottoming cycle. However, water losses for this heat rejection method are high compared to alternative, dry cooling methods. For example, operation of the 1x1 7F.05 combined cycle option (CC-A) would require approximately 1,000 to 1,500 gpm of water during full load operation, depending on ambient conditions.

In areas where water conservation is a high priority or water discharge is not available, air cooled condensers (ACCs) are usually employed. Water losses with an ACC-based heat rejection system are minimal. This method of heat rejection is more expensive in terms of capital cost than a surface condenser and wet mechanical draft cooling tower. Also, the steam turbine exhaust pressure and temperature are typically higher with an ACC, which results in a lower bottoming cycle efficiency compared to wet cooling methods.

O&M costs required to maintain an air cooled condenser are higher than the costs required to maintain a surface condenser and wet mechanical draft cooling tower. However, the cost savings in water treatment chemicals would likely offset the additional maintenance cost. Table B-1 provides a summary comparison for a typical combined cycle operating during hot day conditions. The performance difference during average day conditions would be reduced.

Table B-1 Typical Combined Cycle Wet versus Dry Cooling Comparison

	WET SURFACE CONDENSER/ WET MECHANICAL DRAFT COOLING TOWER	AIR COOLED CONDENSER
Capital Cost	BASE	+5 percent
Net Plant Output	BASE	-1.5 percent
Net Plant Heat Rate	BASE	+1.5 percent

Some peaking plants also rely on large heat rejection systems for proper operation. GE's LMS100 combustion turbine uses a compressor intercooler to cool air leaving the low pressure compressor prior to entering the high pressure compressor. Using an air cooled intercooler loop is possible but results in a much greater hot day performance impact. A summary comparison for an LMS100 operating during typical hot day conditions is presented in Table B-2.

Table B-2 Typical GE LMS100 Wet versus Dry Cooling Comparison

	WET MECHANICAL DRAFT COOLING TOWER	AIR COOLED HEAT EXCHANGER
Capital Cost	BASE	+3 to +5 percent
Net Plant Output	BASE	-5 to -10 percent
Net Plant Heat Rate	BASE	+1 to +3 percent

Wartsila's 18V50SG also relies on a large heat rejection system, mainly for engine jacket cooling. Unlike the LMS100 or a combined cycle's bottoming cycle, the temperatures required are not as stringent. Therefore, the performance impact associated with an air cooled heat exchanger is not nearly as great. However, space requirements for heat rejection equipment may be a concern. The footprint of an air cooled heat exchanger for a single Wartsila 18V50SG engine is roughly 100 feet by 100 feet, which is approximately the space required for the engine itself. One solution would be to locate the air cooled heat exchangers on top of the engine hall. Wartsila has done this as EPC contractor for projects outside the US. However, this approach will result in increased engine hall building costs. Below is a summary comparison for 18V50SG operating during typical hot day conditions.

Table B-3 Typical Wartsila 18V50SG Wet versus Dry Cooling Comparison

	WET MECHANICAL DRAFT COOLING TOWER	AIR COOLED HEAT EXCHANGER
Capital Cost	BASE	+2 percent
Net Plant Output	BASE	-1 percent
Net Plant Heat Rate	BASE	+1 percent

Appendix C. Supplemental HRSG Duct Firing

Supplementary HRSG duct firing is often incorporated into an HRSG design as it allows for increased steam production and resulting increased steam turbine output. Supplemental HRSG duct firing can range from a small amount which allows for constant steam turbine output over the ambient temperature range (i.e., duct firing makes up for the loss in exhaust energy from the combustion turbine at high ambient temperatures) up to a 25 percent increase in net plant output. The burners used for supplementary firing are generally installed in the HRSG, downstream of the final superheater/reheater heat transfer surfaces. The duct burner system consists of pressure reducing station(s); main fuel supply system(s); fuel metering; pilot fuel supply system; cooling air system; augmenting air supply systems; burner elements; flame holders/stabilizers; baffles, scanners; igniters; and piping between associated skids and the HRSG. View ports for visually monitoring the duct burners are provided in the ductwork downstream of burners by the HRSG Supplier. Additionally, skid mounted components for fuel supply, cooling air, and burner management systems are also furnished.

The SCR and oxidation catalysts, as appropriate, can be designed to maintain stack emissions due to the additional contribution of emissions from supplemental duct firing.

To accommodate the additional steam production, the HRSG and steam turbine generator must be designed accordingly. Given that the steam turbine in a combined cycle application is operated in a sliding pressure mode, the unfired throttle pressure will be lower than a comparable combined cycle design with no duct firing capability.

Boiler feed and condensate pump capacity must also be increased to address both fired and steam turbine bypass operation. A fired design, while firing, will result in an increased auxiliary load. Auxiliary loads while in unfired mode may represent a larger percentage of total plant load due to the over-sizing of the balance of plant (BOP) systems to meet fired conditions. In addition, the heat rejection system capacity may be increased to handle the additional heat load when fired while maintaining both desired level of performance and steam turbine backpressure (below alarm limits).

Performance and cost impacts associated with supplemental HRSG duct firing vary greatly with equipment selection. Below are some cost and performance highlights that are typical for supplemental HRSG duct firing designs for utility-scale combined cycle applications:

- **Capital Cost** – The incremental cost associated with a revised HRSG design, larger steam turbine, larger pumps, and associated BOP systems and equipment would be about <u>$300 to $400 per kilowatt of increased net output, on an overnight EPC cost basis.</u> For example, installing the required duct firing systems to provide an increase of 30 MW in steam cycle output would cost approximately $10 million. Considering total capital costs, adding supplemental HRSG duct firing capability to a nominal, un-fired 300 MW-net plant design (and raising the net output to a total of 330 MW) would increase the cost of the combined cycle facility from approximately $300 million to $310 million, <u>on an overnight EPC cost basis</u>.

- **Net Plant Output** – Employing supplemental HRSG duct firing can result in a total net plant output increase of up to about 25 percent if the HRSG is heavily fired. A 10 to 20 percent increase is common.
- **Net Plant Heat Rate** – The incremental net heat rate for supplemental HRSG duct firing is about 8,000 to 9,000 Btu/kWh (HHV). When operating the plant with the CTG(s) at full load and not utilizing the duct burners, the plant heat rate will be impacted slightly because the bottoming cycle would be operating at part-load. This would typically result in about 0.5 percent increase in heat rate. In sliding pressure operation, the steam turbine throttle pressure will be lower. In addition, the steam turbine would only be operating at part load, below its maximum rated output which generally corresponds with the most efficient steam turbine operating conditions.

Appendix D. Peaking Plant Backup Fuel

A backup fuel source can be utilized to increase peaking plant availability and allow for generation to continue during natural gas supply disruptions. Natural gas supply disruptions may occur during peak winter months when residential gas demand is high, among other reasons. The most predominant source of backup fuel is No. 2 distillate fuel, also referred to as diesel fuel. Power plant design, equipment selection, and cost implications associated with constructing a facility with the capability of operating on diesel fuel as a backup fuel source are presented below.

In order to accommodate diesel fuel operating capability, the CTG or RICE package configuration or even model selection will be impacted. For a CTG, model availability might not change but the CTG package will require special design features to accommodate two fuels. These features generally will have no impact on plant output and efficiency while the plant is operating on natural gas but will result in additional equipment and cost. For example, the GE 7F.05 CTG will require a dual fuel package consisting of dual fuel combustors and associated ancillary equipment. While operating on diesel fuel, CTG efficiency will be worse and output will be impacted, either up or down depending on the specific CTG model and dual fuel package limitations. In addition, CTGs utilize water injection for controlling NOx emissions while operating on diesel fuel. NOx water injection rates are often high and CTG water quality specifications call for demineralized water, which can be expensive to produce. NOx water injection requirements are typically anywhere from 0.6 to 1.2 lb water per lb of diesel fuel but vary greatly depending on the CTG model selected.

For reciprocating engines, model availability can be impacted. For example, the Wartsila 18V50SG reciprocating engine (considered in this study) is not capable of dual fuel operation. Instead, the Wartsila 18V50DF dual fuel reciprocating engine would be the Wartsila model offering closest in size and efficiency. The 18V50DF engine has a 9 percent lower output and 3 percent lower efficiency (about 100 Btu/kWh-HHV higher heat rate) than the 18V50SG engine and requires a small amount of diesel fuel consumption (1 percent or less of total fuel input) when operating on natural gas as a primary fuel. Reciprocating engines do not require NOx water injection but rather rely on the SCR system for NOx reductions.

In addition to CTG and reciprocating engine considerations, additional balance of plant systems and equipment would be required to accommodate fuel delivery, storage, forwarding and, in the case of CTGs, demineralized water production, storage, and forwarding. Below is a summary list of plant features required to support diesel fuel operation:

- Diesel truck unloading pad.
- Diesel truck unloading pumps.
- Truck hookups.
- Field erected diesel storage tanks.
- Secondary containment (typically in the form of lined and bermed containment areas in which the tanks are located).
- Diesel fuel forwarding pumps.
- Associated piping and valves.

In addition, the yard fire protection system and foam suppression system will need to be expanded due to the additional fuel oil tanks. A demineralized water production and storage system to support water injection for NOx control will be required. Demineralized water production could be accomplished using demineralized water production trailers and associated trailer parking pads, hookups, and booster pumps as a more economical solution if trailers are readily available and if diesel fuel operation is expected to be limited. For the GE LMS100PA+ CTG, a demineralization system would already be in place (a cost savings on the order of $500,000 per CTG). Additional associated balance of plant facilities such as roads, electrical supply and distribution, foundations, and excavation will also be required. The all-in incremental capital cost impact of constructing a single GE 7F.05 CTG-based peaking power plant with diesel fuel backup capabilities would be approximately $15 million, including three days diesel fuel storage and a demineralized water production and storage system but excluding initial diesel fuel inventory.

Appendix E. Capital and O&M Cost Estimates for Brownfield Projects

Adding new peaking units at an existing PSE generating facility is expected to result in both capital and O&M cost savings compared to constructing equivalent units at Greenfield sites. To help PSE quantify the potential cost savings, Black & Veatch developed brownfield unit addition estimate variants for the following options:

- PP-B: 6x0 Wartsila 18V50SG
- PP-D: 1x0 GE LMS100PA+
- PP-F: 1x0 GE 7F.05

Potential Capital Cost Savings

Assuming sufficient capacity is available at existing facilities, capital cost savings may be possible for power plant facilities and supporting infrastructure such as (but not necessarily limited to) natural gas supply, transmission, water treatment, water storage, site fire protection, buildings, and roads. A breakdown of these line items and rough potential cost savings values are presented in Table E-1.

Table E-1 Potential Capital Cost Savings

COST ITEM	EXPECTED COST SAVINGS VERSUS GREENFIELD	MEAN VALUE
Utility Interconnections	$4 – 10M+	$7M
Demineralized Water Treatment & Storage (1)	$2 – 4M	$3M
Buildings	$2 – 4M	$3M
Site Access Roads	$3 – 5M	$4M
Total Expected Cost Savings	**$9 – 23M+**	**$14M** **$17M (1)**

Notes:
1. Only applicable to the PP-D: 1x0 GE LMS100PA+ option.

To illustrate the potential cost savings, a summary of brownfield capital cost estimates, using the applicable mean values, are summarized in Table E-3.

Potential O&M Cost Savings

The primary difference in O&M costs for Brownfield projects (relative to Greenfield projects) is in reduced fixed labor costs, as the operation of additional units at an existing facility requires only an incremental increase in plant staff. Plant staffing assumptions for Brownfield projects are listed in Table E-2. Estimates of O&M costs for brownfield cases are summarized in Table E-4.

Table E-2 Plant Staffing Assumptions for Brownfield Options

ID	OPTION	PLANT STAFFING	
		GREENFIELD (FTEs)	BROWNFIELD (FTEs)
PP-B	6x0 Wartsila 18V50SG	9	5
PP-D	1x0 GE LMS100PA+	9	5
PP-F	1x0 GE 7F.05	9	5

Table E-3 Summary of Capital Cost Estimates for Brownfield Options

ID	OPTION	AVERAGE DAY NET OUTPUT(1) (MW)	GREENFIELD TOTAL CAPITAL COST		BROWNFIELD TOTAL CAPITAL COST	
			($000)	($/kW)	($000)	($/kW)
PP-B	6x0 Wartsila 18V50SG	111.0	150,800	1,360	136,800	1,230
PP-D	1x0 GE LMS100PA+	113.7	136,500	1,200	119,600	1,050
PP-F	1x0 GE 7F.05	239.0	136,500	570	122,500	510

Notes:

1. Average day net output based on ambient conditions of 51°F and relative humidity of 75%.

Table E-4 Summary of O&M Cost Estimates for Brownfield Options

ID	OPTION	AVERAGE DAY NET OUTPUT(1) (MW)	GREENFIELD ANNUAL FIXED O&M		BROWNFIELD ANNUAL FIXED O&M	
			($000)	($/kW-yr)	($000)	($/kW-yr)
PP-B	6x0 Wartsila 18V50SG	111.0	1,420	12.8	850	7.7
PP-D	1x0 GE LMS100PA+	113.7	1,390	12.2	803	7.1
PP-F	1x0 GE 7F.05	239.0	1,540	6.4	990	4.1

Notes:

1. Average day net output based on ambient conditions of 51°F and relative humidity of 75%.

Appendix F. Wartsila Recommended Maintenance Intervals

04. Maintenance schedule

V2

Regular maintenance of the engine should be performed according to the maintenance schedule. Regular maintenance helps to avoid malfunction of the engine and increases its lifespan.

The actual operating conditions and the quality of the fuel used have a large impact on the recommended maintenance intervals. Because of the difficulty in anticipating the engine operating conditions encountered in the field, the maintenance intervals stated in the schedule are for guidance only.

Note!
During the warranty period, the maintenance intervals must not be exceeded.

If there is any sign indicating the need for a maintenance operation in advance of the scheduled time, prudent industry practice dictates that the maintenance operation be performed. Likewise, if an inspection or observation reveals wear of any part or use beyond the prescribed tolerances, the part should be replaced immediately.

In some cases, the fuel quality used affects the length of the maintenance intervals.

For maintenance instructions, see the references given in the schedule. See also the turbocharger instructions and other equipment manufacturer's instructions.

04.1. Basic maintenance principles

V1

- Observe utmost cleanliness and order during all maintenance work.
- Before dismantling, check that all concerned systems are drained and the pressure released.
- After dismantling, immediately cover the lubricating oil, fuel oil and air holes with tape, plugs, clean cloth or similar means.
- When exchanging a worn-out or damaged part provided with an identification mark stating cylinder or bearing number, mark the new part with the same number on the same spot. Enter every exchange in the engine log along with the clearly stated reason for the exchange.

- Always renew all gaskets, sealing rings and O-rings at maintenance work.

Note!
The O-rings in the cooling water system must not be lubricated with oil based lubricants, use soap or similar.

- After reassembling, check that all screws and nuts are tightened and locked (as required).
- If any welding is performed on the engine, disconnect the electronic equipment according to the welding instructions. Keep the return connection near the welding point.
- Consider that well cleaned oil spaces (oil sump and camshaft spaces) spare the oil pump and oil filter.

04.2. Before starting maintenance work

V4

Do the following before starting to do any maintenance work on the engine (unless it can be done with the engine running):

- Ensure that the automatic start of the engine and all concerned circulation pumps (for instance, lubrication oil, cooling water and fuel) are disconnected.
- Close the starting air shut-off valve located before the main starting valve. Drain the engine starting air system to avoid engine damage and/or personal injury.
- To avoid accidental turning of the engine, secure the generator breaker or disengage the gear box.

Warning!
Accidental turning of the engine may cause engine damages and/or personal injury.

- Disconnect the power supply if electrical components will be removed.

04.3. Maintenance intervals

04.3.1. Daily routine inspections

V1

Part or system	Maintenance task	See
Gas system	Inspect the gas system for leakage using a hand held gas detector.	Chapter 17
Oil mist detector (if installed)	Observe normal operation.	
Pneumatic system	Drain condensated water.	Chapter 21

04.3.2. Every second day

V1

Part or system	Maintenance task	See
Automatic pre-lubrication	Check the operation of automatic pre-lubrication. Replace parts, if necessary.	Chapter 03

04.3.3. Once a week

V1

Part or system	Maintenance task	See
Start process	Test start. (if the engine is on stand-by)	Chapter 03

Note!
The maintenance task is irrespective of the engine being in operation or not.

04.3.4. Every second week

V1

Part or system	Maintenance task	See
Start process	Check water quality. Check content of additives.	Chapter 19 Chapter 02

Note!
The maintenance task is irrespective of the engine being in operation or not.

04.3.5. Interval: 50 operating hours

V1

Part or system	Maintenance task	See
Air cooler(s)	Check draining of the air cooler(s). Check that the draining pipes are open. Check if there is any leakage.	Chapter 15 Chapter 03
Automation	Check and record all operating values.	Chapter 03
Cooling water system	Check the water level in the expansion tank(s). Check the static pressure in the engine cooling circuits. Inspect that the ventilation (de-aerating) of the expansion tank is working.	Chapter 19
Gas and lubricating oil filters	Check pressure drop indicators. Replace filter cartridges if high pressure drop is indicated.	Chapter 17 Chapter 18
Turbocharger	Clean the compressor by injecting water.	Chapter 15
Valve mechanism	Check the valve clearances after 50 running hours in new and overhauled engines.	Chapter 12 Chapter 06

04.3.6. Interval: 500 operating hours

V1

Part or system	Maintenance task	See
Centrifugal filter	Clean centrifugal filter(s). Clean more often, if necessary. Remember to open the valve before the filter after cleaning.	Chapter 18
Charge air cooler	Measure the pressure drop over charge air cooler(s) using U-gauge or tool no. 848051.	Chapter 15
Lubricating oil	In a new installation or after changing to a new lubricating oil brand, take oil samples for analysis.	Chapter 02
Oil mist detector (if installed)	Inspect the functioning. See manufacturer's instructions.	
Wastegate valve	Inspect the functioning.	Chapter 15
By-pass valve (if installed)	Inspect the functioning.	Chapter 15

04.3.7. Interval: 1000 operating hours

V1

Part or system	Maintenance task	See
Air filter (on-built)	Remove the turbocharger air filter(s). Clean according to manufacturer's instructions. Clean more often, if necessary.	Chapter 15
Electrical lubricating oil pump	Regrease pre-lubricating pump under running condition.	Chapter 18
Engine fastening bolts	Inspect the tightening of engine fastening bolts on new installations.	
Gas filter Engine mounted	Clean gas filter cartridges. The engine mounted filter can be cleaned by pressurised air from inside. Replace cartridge, if necessary. (The cartridge must be replaced earlier if the pressure difference indicator shows very high pressure drop.) Clean the filter housing outside and inside. Follow intervals for the filter at 4000 operating hours.	Chapter 17
Gas filter On gas regulating unit	Replace the filter cartridge. Clean the filter housing outside and inside. Follow intervals for the filter at 4000 operating hours or when the pressure difference indicator shows pressure drop higher than 0.5 bar.	Chapter 17

04.3.8. Interval: 2000 operating hours

V1

Part or system	Maintenance task	See
Automation	Check the functioning of the safety system. Check the functioning of the sensors for the alarm system and automatic stop devices.	Chapter 23 Chapter 01
Gas system	Perform the leak test.	Chapter 17
Ignition system	Replace spark plugs if the engine is running more or less continuously. (Maintenance intervals can be shorter if the engine is started/stopped daily or more often.) Clean and check the condition of the ignition coil on plug if the engine is running more or less continuously. Replace O-rings.	Chapter 16
Lubricating oil filter	Inspect and clean lubricating oil filter. (It must be cleaned earlier if the pressure difference indicator shows very high pressure drop.) Drain the filter housings. Clean the wire gauze and filter housing.	Chapter 18
Oil mist detector (if installed)	Replace fresh air filter. See manufacturer's instructions.	
Valves	Check yoke and valve clearances.	Chapter 12 Chapter 06
Valve rotators	Check valve rotators visually.	Chapter 12 Chapter 06

04.3.9. Interval: 4000 operating hours

V2

Part or system	Maintenance task	See
Air cooler(s)	Clean the charge air cooler(s). (Cleaning interval is based on the cooling performance of the air cooler.) Perform the pressure test. Look carefully for corrosion. Measure the pressure difference over the charge air cooler before and after cleaning using U-gauge.	Chapter 15
Automation	Check connectors and cables. Check mounting and connections. Apply contact lubricant to contact surfaces. Check tightness of connections. Check condition of cables, wires and cable glands. Replace damaged connectors and cables.	Chapter 23
Camshaft	Inspect contact faces of the camshaft. Check the contact faces of the cams and tappet rollers. Check that the rollers rotate. Rotate the engine with the turning gear.	Chapter 14 Chapter 03
Crankshaft	Check crankshaft alignment using form no. 4611V005. It is not necessary to perform an alignment check if the engine is mounted on rubber.	Chapter 11
Flexible coupling Vulkan-Rato-S/R	Inspect the flexible coupling visually. See manufacturer's instructions.	
Flexible coupling	Check the alignment of flexible coupling using form no. WV98V041.	
Flexible mounting (if used)	Check the alignment . Check compression of the thrust rubber elements. Inspect according to maintenance instructions for resilient installation. See technical documents.	
Gas filter	Replace gas filter cartridges. (The cartridge must be replaced earlier if the pressure difference indicator shows very high pressure drop.) Clean the filter housing outside and inside.	Chapter 17
Gas filter On gas regulating unit	Replace gas filter cartridges. (The cartridge must be replaced earlier if the pressure difference indicator shows pressure drop higher than 0.5 bar.) Clean the filter housing outside and inside.	Chapter 17
Wastegate	Check the wastegate valve and the actuator. Change the positioner pilot valve.	Chapter 15

04.3.10. Interval: 6000 operating hours

V1

Part or system	Maintenance task	See
Flexible pipe connections	Inspect flexible pipe connections. Renew, if necessary.	
Exhaust manifold	Inspect expansion bellows. Replace parts, if necessary. Inspect supports of the exhaust system.	Chapter 20

04.3.11. Interval: 8000 operating hours

V1

Part or system	Maintenance task	See
Automation	Check wiring condition inside the cabinets and boxes. Check for wear of insulation, loose terminations, loose wires and leakages. Check wear of cable insulation, breakages, loose cable glands, connectors, holders and loose grounding shields. Check for loose grounding straps and corrosion. Check sensors, actuators, solenoids etc. for leakages, physical damages. Check signal/measurement also where applicable. Check soft dampers condition if its flattened, worn out or broken. Check if the electrical displays/meters are dark or broken. Check electronic modules visually for damages, leakages or smoke residuals. Rectify, improve or replace the equipment, if necessary.	Chapter 23

04.3.12. Interval: 9000 operating hours

V1

Part or system	Maintenance task	See
Prechamber	Check prechamber tip for possible wear or cracks.	Chapter 16
Prechamber valve	Clean the prechamber valve. Check the prechamber valve for wear. Renew parts, if necessary.	Chapter 16

04.3.13. Interval: 12000 operating hours

V1

Part or system	Maintenance task	See
Air filter (in pneumatic systems)	Clean the filter. Clean the filter cartridge and replace , if necessary. Clean the filter housing outside and inside.	Chapter 21
Flexible pipe connections	Renew flexible pipe connections. Depending on the condition of the connection and the target of usage, these pipe connections can be used even for longer.	
Oil mist detector (if installed)	Replace the oil mist detector supply air filter. See manufacturer's instructions.	
Turbocaharger(s)	Dismount and clean. Inspect and assess the shaft and the bearing parts. Clean the compressor casings. Check for any crack ,erosion or corrosion. Clean nozzle ring and check for any crack or erosion. Measure and note the axial clearance. If the clearance is out of tolerance, contact the engine manufacturer. See manufacturer's instructions.	Chapter 15
Turbocharger(s) ABB TPL- chargers	Inspect the turbocharger bearings. Replace the bearings at 36000 hours at the latest , if necessary. See manufacturer's instructions.	Chapter 15
Turning device	Grease the drive shaft of the turning device.	Chapter 11
Wastegate	General overhaul of the wastegate valve and the actuator. Change the positioner pilot valve.	Chapter 15

04.3.14. Interval: 18000 operating hours

V1

Part or system	Maintenance task	See
Air cooler(s)	Clean the charge air cooler(s). Clean more often, if necessary. (Cleaning interval is based on the cooling performance of the cooler.)	Chapter 15
Camshaft driving gear	Inspect intermediate gears. Inspect teeth surfaces and running pattern. Replace parts, if necessary.	Chapter 13 Chapter 06
Connecting rods	Inspect big end bearing, one/bank. Dismantle the big end bearing. Inspect mating surfaces. If defects are found, open all big end bearings. Renew bearing shells, if necessary. Refer measurement record 4611V008 and 4611V003.	Chapter 11 Chapter 06
Connecting rods	Check small end bearing and piston pin, one/bank. If defects are found, open all and renew if needed. Refer measurement record 4611V004.	Chapter 11 Chapter 06

Part or system	Maintenance task	See
Crankshaft	Inspect main bearings. Inspect one main bearing. If in a bad condition, check/change all main bearings. Note the type of bearing in use and do the inspection accordingly.	Chapter 10 Chapter 06
Crankshaft	Check thrust bearing clearance. Check axial clearance.	Chapter 11 Chapter 06
Cylinder heads	Overhaul of cylinder head. Dismantle and clean the under side, inlet and exhaust valves and ports. Inspect cooling spaces and clean, if the deposits are thicker than 1 mm. If cylinder head cooling water spaces are dirty, check also the cooling water spaces in liners and engine block and clean them all, if the deposits are thicker than 1 mm. Improve the cooling water treatment. Grind all seats and the valves. Inspect the valve rotators. Check rocker arms. Replace O-rings in the valve guides. Replace O-rings at the bottom of the cylinder head screws at every overhaul. Replace the knocking sensors. Check the starting valves. Renew parts, if necessary.	Chapter 12 Chapter 14
Cylinder liners	Inspect the cylinder liners. Measure the bore using form no. 5010V001. Replace liner if wear limits are exceeded. Hone the liners. Check the deposits from cooling bores. If the deposits are thicker than 1 mm, clean the cooling bores. Renew the anti-polishing ring.	Chapter 10 Chapter 06
Engine fastening bolts	Check tightening of the engine fastening bolts.	Chapter 07
Gas admission valves Woodward	Replace the main gas admission valves. In installations where connectors are used, replace the female connector also. Send gas admission valves to the engine manufacturer for reconditioning.	Chapter 17
Gas system	Replace sealings in pipe connections. Check sealing faces for wear and corrosion. Perform the leak test.	Chapter 17
Hydraulic jack	Check the functioning. Replace O-rings in the hydraulic jack if they are leaking when lifting the main bearing cap.	Chapter 10
Ignition system	Replace ignition coil on the plug.	Chapter 16
Pistons	Check the cooling gallery deposit, one piston/bank. If the deposit exceeds 0.3 mm, open all piston tops. Inspect the piston skirt. Clean lubricating oil nozzles.	Chapter 11

Part or system	Maintenance task	See
Pistons, piston rings	Inspect pistons and replace piston rings. Pull, inspect and clean. Check the height of the piston ring grooves using form no. 4611V009 and 4611V002. Check the retainer rings of the gudgeon pins. Replace complete set of piston rings. Note the running-in programme.	Chapter 11 Chapter 06 Chapter 03
Prechamber	Replace the prechamber tip. Check all the parts of prechamber.	Chapter 16
Prechamber valve	Replace the prechamber valve.	Chapter 16
Turning device	Change lubricating oil in the turning device.	Chapter 02
Vibration damper Viscous type	Take oil sample from vibration damper for analysis.	Chapter 14

04.3.15. Interval: 24000 operating hours

V1

Part or system	Maintenance task	See
Automation	Replace drive electronics. (CCM modules on engine control system) The drive electronics must be replaced every 10th year at the latest.	Chapter 23
Automation	Replace vibration dampers used in the control system cabinets, enclosures and modules. Replace the vibration dampers every 24000 operating hours or every four years depending on whichever comes first.	
Exhaust manifold	Renew the expansion bellows between exhaust pipe sections, after the cylinder head and before the turbocharger.	Chapter 20
Flexible coupling (Oil supply from the engine)	Check the flexible coupling. Dismantle and check flexible coupling according to manufacturer's recommendations.	
HT- water pump	Inspect HT-water pump. Dismantle and check. Renew bearings and shaft sealing.	Chapter 19
HT- water pump driving gear	Inspect HT-water pump driving gear. Replace parts, if necessary.	Chapter 19 Chapter 06
HT- water thermostatic valve	Clean and inspect HT- water thermostatic valve. Clean and check the thermostatic element, valve cone-casing, and sealings.	Chapter 19
LT- water pump	Inspect LT-water pump. Dismantle and check. Renew bearings and shaft sealing.	Chapter 19
LT- water pump driving gear	Inspect LT-water pump driving gear. Replace parts, if necessary.	Chapter 19 Chapter 06
LT- water thermostatic valve	Clean and inspect LT- water thermostatic valve. Clean and check the thermostatic element, valve cone-casing, indicator pin and sealings.	Chapter 19

Part or system	Maintenance task	See
Lubricating oil pump	Inspect lubricating oil pump. Renew bearings. Renew shaft sealing.	Chapter 18
Lubricating oil pump driving gear	Inspect lubricating oil pump driving gear. Replace parts, if necessary.	Chapter 18 Chapter 06
Lubricating oil thermostatic valve	Clean and inspect lubricating oil thermostatic valve. Clean and check the thermostatic element, valve cone-casing and sealings.	Chapter 18
Main starting valve	General overhaul of the main starting valve. Replace worn parts.	Chapter 21
Turbocharger(s) ABB TPL- chargers	Inspect turbocharger parts. Inspect and replace nozzle ring , turbine diffuser/cover ring , if necessary. See manufacturer's instructions.	Chapter 15

04.3.16. Interval: 32000 operating hours

V1

Part or system	Maintenance task	See
Turbocharger Napier	Check rotor balance every 32000 hours or every 4 years. See manufacturer's instructions.	Chapter 15

04.3.17. Interval: 36000 operating hours

V1

Part or system	Maintenance task	See
Air cooler(s)	Renew the charge air cooler(s).	Chapter 15
Camshaft	Inspect camshaft bearing bush, one/bank. If defects are found, inspect all including driving end and thrust bearing. Renew, if necessary. Refer measurement record 4610V003.	Chapter 14 Chapter 06
Connecting rods	Replace big end bearing. Replace big end bearing shells. Inspect mating surfaces. Measure the big end bore using form no. 4611V008 and 4611V003.	Chapter 11 Chapter 06
Connecting rods	Replace the small end bearings. Replace the small end bearing shells.	Chapter 11 Chapter 06
Crankshaft	Renew main bearing shells. Renew main bearing shells, flywheel bearings and thrust bearing halves.	Chapter 10 Chapter 06
Crankshaft	Inspect the crankshaft for wear. Renew the crankshaft seal.	Chapter 11

Part or system	Maintenance task	See
Cylinder head	Renew inlet and exhaust valve seats only if wear limits have exceeded or leaks are detected. Renew inlet and exhaust valves. Renew valve rotators and valve guides.	Chapter 12
Cylinder liners	Clean cylinder liner cooling water spaces. Replace the liner O-rings at every overhaul.	Chapter 10
Elastic coupling in camshaft driving end	General overhaul of the elastic coupling. The elastic coupling must be opened only by the authorized personnel. Contact the engine manufacturer.	Chapter 07
Exhaust manifold	Renew exhaust pipe support plates.	Chapter 20
Intermediate gear	Renew thrust bearing of the intermediate gear. Renew bearing bushes of the intermediate gear.	Chapter 13
Piston	Inspect the piston cooling gallery, all cylinders. Clean , if necessary.	Chapter 11
Prechamber	Replace the prechamber.	Chapter 16
Starting air distributor	General overhaul of starting air distributor. Renew worn parts.	Chapter 21
Valve mechanism	Check bearing clearances in the tappets and rocker arms, one/ cylinder. Dismantle one rocker arm assembly for inspection. Proceed with other rocker arm bearings if defects are found. Renew valve tappet roller bearing bushes.	Chapter 12 Chapter 14 Chapter 06
Vibration damper in camshaft free end (spring type, optional)	Dismantle the damper and check its condition. The damper must be opened only by the authorized personnel. Contact the engine manufacturer.	Chapter 07 Chapter 14
Vibration damper in crankshaft free end (spring type, optional)	Dismantle the damper and check its condition. The damper must be opened only by the authorized personnel. Contact the engine manufacturer.	Chapter 07 Chapter 11

04.3.18. Interval: 48000 operating hours

V1

Part or system	Maintenance task	See
Automation	Replace measuring electronics and all the modules on engine control system. The measuring electronics must be replaced every 10th year at the latest.	Chapter 23
Charge air bellow	Renew expansion bellow(s) between the turbocharger and air inlet box.	Chapter 20
Turbocharger	Replace rotor and rotating parts. (Lifetime dependent of operating conditions). See manufacturer's instructions.	Chapter 15
Turbocharger(s) ABB TPL - chargers	Inspect turbocharger gas- inlet/outlet casings. Replace the gas- inlet/outlet casings, if necessary. See manufacturer's instructions.	Chapter 15

04.3.19. Interval: 72000 operating hours

V1

Part or system	Maintenance task	See
Camshaft bearings	Renew camshaft bearings. Renew camshaft driving end bearing bush and camshaft thrust bearings.	Chapter 13 Chapter 14
Cylinder heads	Renew cylinder heads.	Chapter 12
Flexible mounting (if used)	Renew rubber elements. See technical documents.	
Piston	Renew pistons and gudgeon pins.	Chapter 11
Valve mechanism	Renew rocker arm bearing bushes.	Chapter 12 Chapter 14