# THERMAL AND PUMPED STORAGE GENERATION OPTIONS

Supply Side Resource Plants

HDR Project #10104560

*Portland General Electric*

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# THERMAL AND PUMPED STORAGE SUPPLY SIDE RESOURCE OPTIONS

# SUPPLY SIDE RESOURCE PLANTS

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# Executive Summary

Portland General Electric (PGE) is preparing its 2019 integrated resource plan (IRP) and is evaluating several supply-side resources including thermal, renewable, and storage technologies. HDR Engineering, Inc. (HDR) was retained by PGE to assist with the overall 2019 IRP effort by characterizing the operational and cost attributes of various power generation technologies. HDR provides consulting, design, and Owner's engineering services for all aspects of power generation, including thermal, hydro, renewable, and energy storage projects. The parameters developed for each technology include estimated performance and operating characteristics, capital costs, operating costs, and implementation schedules. The range of technologies considered include several natural gas fired generating options, a geothermal technology, and a pumped storage hydro technology. The resulting parameters for the various technologies are summarized in Table E-1 for representative project sites in the Pacific Northwest. The following summarizes the basis for development of the parameters for each of the technologies:

1. Performance has been estimated for all options based on supplier feedback and performance estimating software.
2. Plant steady state emissions were estimated.
3. Conceptual level project capital costs have been developed based on an overnight, turnkey engineer, procure, and construct (EPC) delivery in 2018$.
4. End of life decommissioning, net of salvage value, were estimated.
5. Technology maturity / cost forecasts were projected.
6. Conceptual level operations and maintenance (O&M) costs, including both fixed and variable O&M, were estimated and are presented in $/kW-yr and $/MWh, respectively.
7. Conceptual level project implementation schedules identifying key project milestones and duration of key project activities from EPC contractor notice to proceed (NTP) to the commercial operation date (COD) of the facility are presented.
8. Capital drawdown schedules were developed.
9. Input parameters for dispatch modeling were derived from the O&M costs and various operating characteristics developed for each option.

Additional details and results regarding the development of the generating resource characteristics are further summarized in this report. The information developed for the IRP activities are intended to represent the current energy industry landscape and are based on supplier-, site-, and project-generic technologies. Technology attributes are suitable for comparative purposes, should not be used for budget planning purposes, and are subject to refinement based on further evaluation and review.

## Table E-1. Summary of Technology Attributes.[1234]

| | Unit Type | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE | 30 MW Biomass | 30 MW Geo-thermal | 1200 MW Pumped Hydro |
|---|---|---|---|---|---|---|---|---|
| Fuel | Type | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Wood | NA | NA |
| Average Day Capacity, New & Clean[1] | (MW) | 96 | 356 | 517 | 109 | 30.5 | 30 | 1,149 |
| Average Day Net HHV Heat Rate, New & Clean[1] | (Btu/kWH) | 8,930 | 9,135 | 6,232 | 8,453 | 13,450 | NA | NA |
| Average Day Degraded Capacity[1] | (MW) | 93 | 347 | 503 | 108 | 30 | 23 | |
| Average Day Degraded Heat Rate[1] | (Btu/kWH) | 9,094 | 9,298 | 6,362 | 8,534 | 13,731 | N/A | |
| Capital Cost[2] | $/kW | $1,154 | $531 | $906 | $1,265 | $5,935 | $6,216 | $2,252 |
| Capacity Factor[3] | (%) | 10% | 10% | 75% | 20% | 92% | 93% | 37% |
| Fixed O&M[4] | ($/kW-yr) | $5.61 | $2.10 | $6.57 | $5.15 | $110.84 | $119.53 | $11.31 |
| Variable O&M[4] | ($/MWH) | $5.20 | $9.69 | $3.57 | $5.42 | $5.28 | $2.39 | $0.37 |
| | | | | | | | | |
| Project Schedule | (months) | 22 | 22 | 36 | 18 | 43 | 36 | 60-96 |

[1] Average day conditions is 55 F. Thermal heat rates are presented on a higher heating value (HHV) basis.
[2] $/kW capital cost metrics divide estimated project costs by the average new and clean capacity for a given technology. Costs are 2018 US$.
[3] Capacity factors for dispatchable technologies assumed in order to develop O&M costs.
[4] O&M costs are divided by average life of plant degraded net plant output at average day conditions. Costs are 2018 US$.

# 1 Introduction

Portland General Electric (PGE) is preparing its 2019 integrated resource plan (IRP) and is evaluating several supply-side resources including thermal, renewable, and storage technologies. HDR Engineering, Inc. (HDR) was retained by PGE to characterize a select group of thermal generating resources and a pumped hydro resource. The developed resource characteristics will be used by PGE for development of modeling inputs and assumptions to be used in its 2019 IRP development and dispatch models. These technology characteristics include estimated performance and operating attributes, capital costs, and operating costs for the various generating technologies. The technology options considered include several natural gas fired generating alternatives, geothermal generation, and pumped hydro energy storage generation. The following report summarizes the assumptions, calculations, and analyses to characterize the resource options and discusses current market conditions that may alter the accuracy of these inputs or the ability of PGE to implement the technologies considered in this study.

The following thermal and pumped hydro storage generating resource options were considered:

1. Simple Cycle (SC) Aeroderivative Combustion Turbine Generator (CTG) – Nominal 96 MW capacity.
2. Simple Cycle Frame Combustion Turbine Generator – Nominal 356 MW capacity.
3. Combined Cycle (CC) Combustion Turbine Generator – Nominal 517 MW capacity in a 1x1 configuration.
4. Simple Cycle Reciprocating Engine Generators (RICE) – Nominal 109 MW capacity in a 6x0 configuration.
5. 30 MW Biomass Fired Steam Plant
6. 30 MW Geothermal Plant
7. 1200 MW Pumped Storage Hydro Plant

HDR has developed the following characteristics for each of the generation options:

1. Plant Capacity and Performance
2. Operational Characterization
    a. Ramp rates
    b. Availability / Reliability
    c. Minimum Up / Down Times
    d. Start-Up Times
    e. Maintenance Cycle / Durations
    f. Approximate Footprint
    g. Plant Emissions
    h. Water Requirements
    i. Technical Maturity
3. Plant Capital Costs
    a. Project Costs
    b. Owner's Costs

4. Project Schedule
5. Operations and Maintenance Costs
    a. Fixed Costs
    b. Variable Costs

The details and results of the plant characteristics developed by HDR are further discussed in the following sections of this report and are summarized in Appendix E.

# 2 Study Basis and Assumptions

The following basis was used for establishing performance, costs, and operating characteristics for the various generating resource options considered in this study.

## 2.1 Site Characteristics

The generation technologies described in this report have been presented on the basis that installations are assumed to be located in the Pacific Northwest.

Summer, average, and winter day ambient climate information was developed based on the site conditions indicated in Table 2.1-1. Plant part load performance was also developed at ISO ambient conditions.

**Table 2.1-1. Site Ambient Conditions**

| Site Conditions | | Summer | Average | Winter | ISO |
|---|---|---|---|---|---|
| **Dry Bulb Temperature** | **F** | 90 | 55 | 20 | 59 |
| **Wet Bulb Temperature** | **F** | 67.18 | 48 | 18.33 | 51.47 |
| **Relative Humidity** | **%** | 30% | 60% | 75% | 60% |
| **Site Elevation** | **ft** | 1000 | 1000 | 1000 | 1000 |

## 2.2 Plant Performance

### 2.2.1 Performance

Plant performance (i.e., output, efficiency, etc.) was estimated for all technologies based on performance estimating software, previous project developments, feedback from equipment suppliers, and/or published performance information.

For the thermal generation options, performance was developed based on prime mover performance provided by original equipment manufacturers (OEMs), ThermoFlow performance estimating software, and estimates of facility auxiliary loads. Heat balance diagrams were developed for summer and average day ambient conditions at full load. Full load heat balance diagrams for the thermal options are provided in Appendix A.

Average life of plant degraded plant performance was also developed based on the capacity factor and dispatch identified in Table 2.3-4. Part load operating conditions were also developed at ISO conditions at average life of plant degraded performance. In all degraded cases, it was assumed that at least one complete maintenance interval or major overhaul was completed during the life of the plant.

### 2.2.2 Air Emissions

For the thermal technologies, plant air emissions were estimated at steady-state, full load operation based on supplier-provided emission profiles and assumed fuel characteristics. Emissions estimated for this evaluation are not intended to be used for permitting activities and are intended to provide a comparison between the different thermal technologies.

### 2.2.3 Water Resources

Plant water consumption and wastewater discharge was estimated for the thermal technologies based on conceptual plant water management systems typically applied to current applications. Water users typically included:

- CTG Evaporative Coolers (summer operation only)
- NOx water injection (aeroderivative CTG)
- Steam cycle makeup
- Wet cooled heat rejection system makeup due to evaporative losses and blowdown
- Miscellaneous users, primarily consisting of plant personnel water usage

Wastewater discharge primarily is from:

- Wet cooled heat rejection system blowdown
- Steam cycle blowdown
- Evaporative cooler blowdown

Evaporative losses and water replenishment from the reservoir are not included for the pumped hydro energy storage resource option.

### 2.2.4 Fuel Assumptions

Natural gas was evaluated as the fuel source for the combustion turbine and reciprocating engine options. Fuel gas is assumed available at a utility interface on-site at 600 psia with a fuel heating value of 22,029 Btu/lb.

For the biomass generating option, a typical chipped wood biomass fuel was assumed. The biomass fuel analysis is characterized in Table 2.2-2.

### Table 2.2-2. Biomass Fuel Analysis

| Biomass Fuel | | |
|---|---|---|
| Type: Biomass--Wood | | |
| Fuel supply temperature | 77 | F |
| LHV (moisture and ash included) | 3695 | BTU/lb |
| HHV (moisture and ash included) | 4429 | BTU/lb |
| **Ultimate Analysis (weight %)** | | |
| Moisture | 48.91 | % |
| Ash | 2.03 | % |
| Carbon | 25.69 | % |
| Hydrogen | 2.35 | % |
| Nitrogen | 0.53 | % |
| Chlorine | 0.02 | % |
| Sulfur | 0.06 | % |
| Oxygen | 20.41 | % |
| Total | 100 | % |
| **Proximate Analysis (weight %)** | | |
| Moisture | 48.91 | % |
| Ash | 2.03 | % |
| Volatile Matter | 42.1 | % |
| Fixed Carbon | 6.96 | % |
| Total | 100 | % |
| **Other Properties** | | |
| Specific Heat @ 77F, dry | 0.4036 | BTU/lb-R |
| Specific Heat @ 572F, dry | 0.6114 | BTU/lb-R |
| Bulk density | 16 | lbm/ft^3 |
| Mercury content (dry basis) | 0 | ppmw |
| **Ash Analysis (weight %)** | | |
| SiO2 | 17.78 | % |
| Al2O3 | 3.55 | % |
| Fe2O3 | 1.58 | % |
| CaO | 45.46 | % |
| MgO | 7.48 | % |
| Na2O | 2.13 | % |
| K2O | 8.52 | % |
| TiO2 | 0.5 | % |
| P2O5 | 7.44 | % |
| SO3 | 2.78 | % |
| Other | 2.78 | % |
| Total | 100 | % |

## 2.3 Operating and Maintenance Cost Assumptions

For each technology resource considered, operating and maintenance (O&M) costs are presented and are broken into fixed and variable costs. O&M costs are estimated based on a combination of previous HDR project experience or vendor information available such as combustion turbine long term service agreement pricing.

While these costs vary from technology to technology, the fundamental breakdown between fixed and variable costs can be summarized as follows:

**Fixed O&M**: Fixed O&M costs are costs that are not generally dependent on the generation rate of the facility. These costs take into account plant operating and maintenance staff, fixed long term service agreement costs, and other fixed maintenance costs for equipment. Fixed staffing costs utilized in the analysis are defined below in Table 2.3-1. Typical plant staffing levels used for characterizing staffing costs are summarized in Table 2.3-2. For the simple cycle options, it is assumed the plant is located at an existing plant site with minimal staff additions. No taxes, insurances, corporate general and administrative costs (G&A), fixed fuel transportation, or fixed transmission costs have been included.

### Table 2.3-1. Fixed Staffing Costs.

| Fixed Cost | Cost in 2018 $ |
|---|---|
| Annual Cost for Salaried Staff | $140,000 |
| Annual Cost for Hourly Staff | $100,000 |

### Table 2.3-2. Plant Staffing Level Basis.

| Staffing | | Simple Cycle / Engines | 1x1 Combined Cycle | Biomass | Geothermal | Pumped Hydro |
|---|---|---|---|---|---|---|
| Incremental Salaried Staff | | 1 | 6 | 9 | 4 | 3 |
| Incremental Hourly Staff | | 2 | 18 | 19 | 10 | 25 |

Fixed costs developed for this evaluation are presented on a $/kW-yr basis computed by dividing the estimated fixed annual O&M costs by the average life of plant degraded full load net plant output at average day ambient conditions.

**Variable O&M**: Variable O&M costs are those expenses that are dependent on electrical production/operation of a facility. Variable O&M costs presented herein generally are non-fuel variable O&M costs unless stated otherwise. Non-fuel variable costs include costs for delivery and disposal of all materials utilized in the power generation process, including ammonia, lime, limestone, activated carbon, water, water treatment chemicals, ash and waste disposal. Also included are major equipment and maintenance costs, including replacement material and components and outsourced labor to perform major maintenance on the combustion turbines, steam turbines, boilers, air quality control equipment, material handling systems, and other major equipment. It was assumed that at least one complete maintenance interval or major overhaul was completed during the life of the plant for all options.

Commodity costs required for determining variable maintenance costs are summarized in Table 2.3-3.

**Table 2.3-3. Consumable Costs.**

| Consumable | Unit Cost in 2018 $ |
|---|---|
| Ammonia | $166.52 / Ton (as 19% NH3) |
| Makeup Water | $1.50 / kgal |
| Demin Water | $3.50 / kgal |
| Cycle Chemical Feed | $0.015 / Ton steam produced |
| Waste Water Treatment | $1.00 / kgal |
| Engine Lube Oil | $7.00 / kgal |
| Sand (CFB bed material) | $7.20 / Ton |
| Limestone | $14.00 / Ton |
| Fly Ash Disposal (Offsite) | $20.00 / Ton |

Variable O&M costs are presented herein on a $/MWh basis however, for some technologies, variable O&M costs can be broken down into electric production-based ($/MWh) and/or operation-based ($/hour of operation or $/start) costs. Operation based costs are generally included in the CTG or RICE long term service contract costs.

O&M costs have been developed for each technology option based on the following general plant dispatch profile in Table 2.3-4.

**Table 2.3-4. Plant Dispatch.**

| Plant Annual Dispatch Basis | | |
|---|---|---|
| Simple Cycle / Engines | 10% | peaking dispatch |
| Combined Cycle | 75% | intermediate to baseload dispatch |
| Biomass / Geothermal | 90% | baseload |
| Pumped Hydro | 37% | 8 hours storage duration, daily dispatch |

## 2.4 Capital Cost Basis & Uncertainty Basis

Total project capital costs were developed assuming an engineer, procure and construct (EPC) contracting basis and are presented in this report based upon a project full notice to proceed (FNTP) in 2018. These costs assume that each of the technologies considered will be installed within the Pacific Northwest. Oregon specific wage rates and productivity factors have been utilized for the natural gas and biomass project estimates. General adjustments have been applied to the other technology options to consider an Oregon based installation.

Total capital cost estimates are broken down into project capital and Owner's costs. Project capital costs include the following:

- The costs associated with the procurement of major equipment (equipment costs)

- Costs associated with construction labor (construction costs)
- Costs associated with the procurement of commodities such as piping, valving, insulation, instrumentation, etc. (materials and supplies costs)
- Project indirects
- Construction management
- Engineering
- Contingency
- EPC fees and insurance

Owner's costs have generally been developed as a percentage of project capital costs and include the following (unless otherwise noted within the report[5]):

- Project management (0.6%)
- Engineering support (0.4%)
- Construction management (0.3%)
- Owner contingency (10%)
- Plant operations during commissioning (0.4%)
- Insurance during construction (0.8%)
- Initial spares (0.6%)
- Construction utilities (0.3%)
- Project development and permitting (excludes Oregon Energy Facility Citing Council (EFSC) carbon offset payments) (1.1%)
- Miscellaneous (0.4%)
- Long term service agreement (LTSA / continuing service agreement (CSA) initiation fees (0.38%)
- Land purchases, assuming $2,310 per acre land cost.

Project development costs for geothermal also include field well development costs that typically are incurred by the Owner prior to EPC FNTP and are included in the Owner's costs.

The following additional general site assumptions have been used:

- Costs are inclusive of the plant site boundary.
  - For natural gas projects, this is from the utility gas yard interface on-site to the high side of the generator step up transformers.
  - Potable water, service water, make-up water, fire water, and waste water will interface with a local utility at the site boundary.
- Project costs generally assume a greenfield installation. The simple cycle resources assume they will be located at an existing site with minimal shared infrastructure.
- Sufficient space is available at the site for construction activities, including lay-down.

[5] Pumped hydro Owner's costs are estimated to be approximately 20%.

- No costs have been included for transmission interconnect costs, escalation, accrued finance during construction (AFDC) charges, finance fees, or sales tax.

All project total capital costs that are expressed as $/kW values in this report are derived by dividing the project costs by the net plant capacity under new and clean average day operating conditions.

All costs presented herein are based upon current day cost expectations and actual project data and quotations where available. They are intended to reflect the current status of the industry with respect to recent materials and labor escalation; however, due to the volatility of the power generation marketplace, actual project costs should be expected to vary. Each project cost summary provides an indication of estimated accuracy of the total project cost values based on whether the estimate is an American Association of Cost Engineering International (AACE) Class 4 or 5 estimate (depending on technology). The expected standard deviation of the cost has been calculated based on the accuracy of the cost estimate. Estimate uncertainty is characterized further in Table 2.4-1, where low corresponds to a low range of estimation (or underestimation) and high corresponds to a high range of estimation (or overestimation).

**Table 2.4-1. Estimate Uncertainty**

| Estimate Class | Accuracy Range | |
|---|---|---|
| | Low | High |
| Class 5 | -20 to -50 % | +30 to +100% |
| Class 4 | -15 to -30% | +20 to +50% |

Decommissioning costs have also been estimated, net of salvage value, and assume the site will be restored back to a brownfield condition, which removes all material and structures down to 2 to 3 ft. below grade. For geothermal, it is assumed the well heads are filled and capped. For pumped hydro, it is assumed the reservoir embankment has been breached and tunnels are filled and left in place below grade. Decommissioning costs are presented in 2018 US dollars and reflect HDR's opinion of current market conditions and salvage costs and do not include escalation to the end of project life. These costs have been estimated based on similar project experience or as a percentage of capital costs.

## 2.5 Technology Maturity

As more experience is gained through the application of a power generation technology, the capital costs would be expected to decrease as the design, fabrication, and installation of a technology becomes more mature. To estimate the effects of maturity on a generation technology, and the potential reductions in plant capital costs over time, cost trends were developed using data from the Energy Information Administration's (EIA) 2017 Annual Energy Outlook (AEO) National Energy Modeling System (NEMS). Cost forecasting data from NEMS was applied to the estimated capital costs as a basis for forecasting future costs for each technology option evaluated. All costs are referenced in 2018 US dollars and are forecasted from 2018 to 2050. In most cases, the NEMS forecasted cost projections did not start until 2020 or 2021, so costs were estimated to be unchanged from 2018 until the start of the NEMS forecast. Figure 2.5-1 summarizes the results of the estimated future project costs. Further details are included in Appendix B. It is also noted that the geothermal cost forecast assumes that the most viable sites will be utilized first and, once those sources are depleted, project costs will increase over time due to the decrease in the quality of the geothermal sites to be utilized (hence the oscillating cost curve).

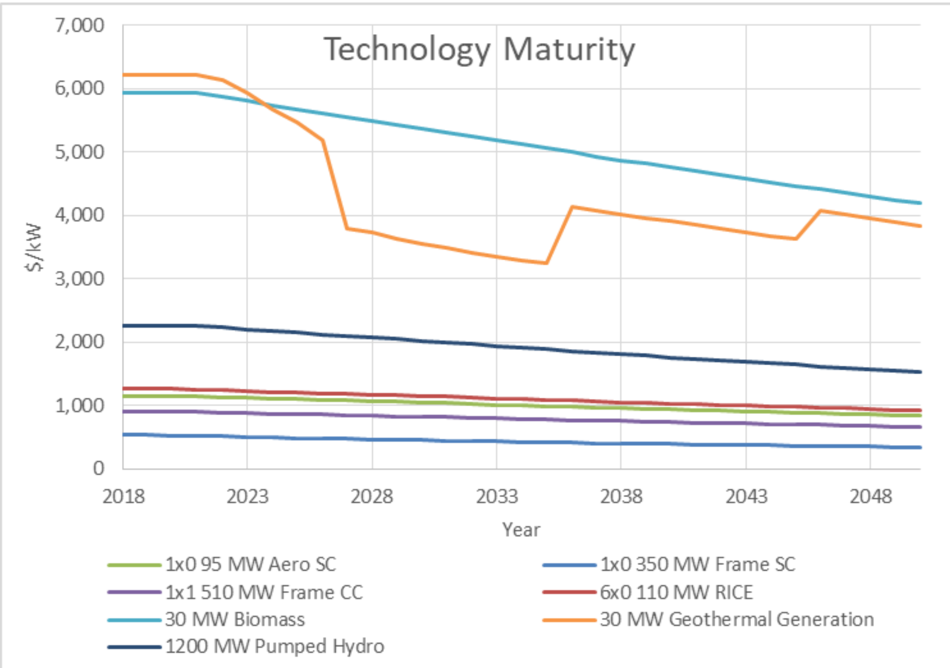


**Figure 2.5-1. Technology Maturity / Cost Forecast**

## 2.6 Project Schedule and Cash Flow Basis

The estimated project schedules presented herein are based upon current day EPC contracting approaches and methodologies. As such, for natural gas fired generation resources, it is expected that a significant portion of preliminary engineering and equipment sourcing activities are completed prior to the FNTP of the project. This will typically involve the procurement of the major equipment and the EPC contract assuming limited notice to proceed (LNTP) is awarded for these contracts prior to an FNTP.

While some project schedules estimated for this work include some developmental activities, the majority of the schedules and durations are generally presented from Full Notice to Proceed to the commercial operation date (COD) of the facility. It is expected that the air permit will be received and project financing activities will be completed prior to the project FNTP.

In the case of geothermal, significant costs are typical incurred for field well development prior to FNTP.

For monthly cash flow determinations a general project cash flow schedule has been utilized and adjusted as appropriate for each technology. A general representation of the curve is presented in Figure 2.6-1. Annual cash flow forecasts are provided for each technology from FNTP to the commercial operation date (COD).

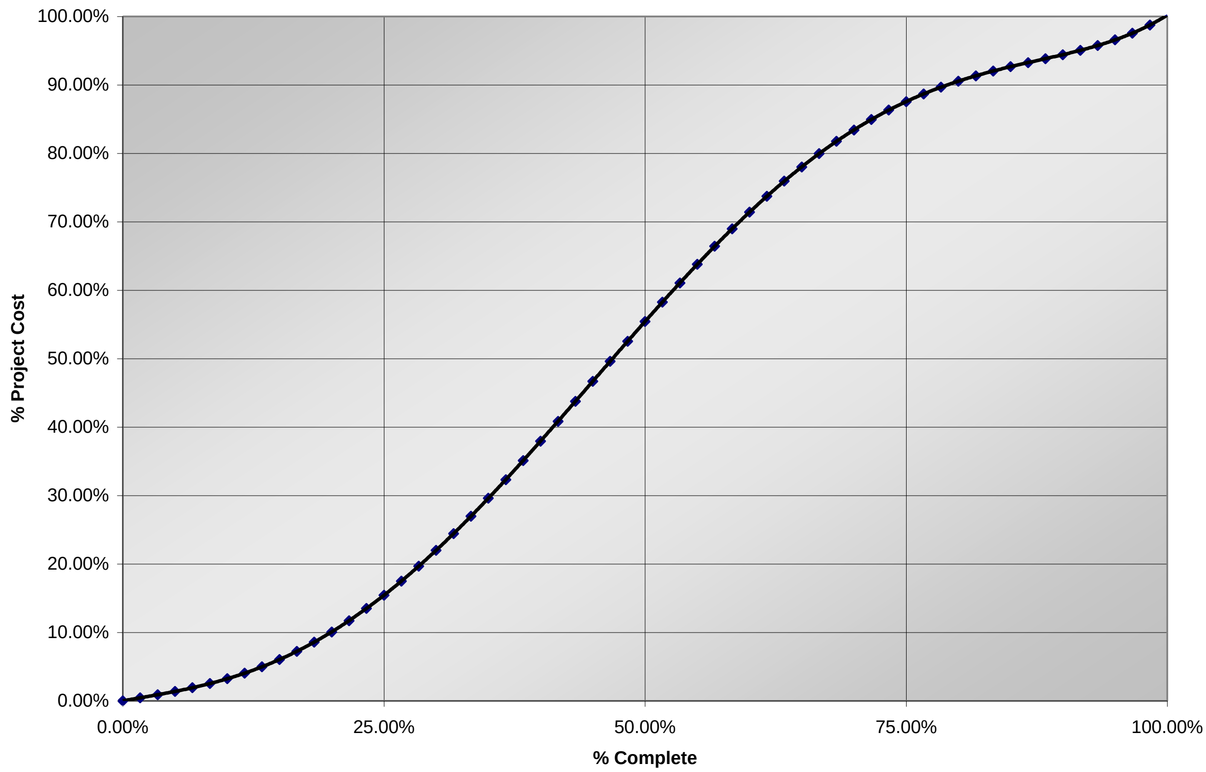


**Figure 2.6-1. Representative Cash Flow Curve.**

Annual cash flow forecasts are presented for each technology on a calendar month basis from FNTP to the commercial operation date (COD) in Appendix D.

# 3 Natural Gas Generation Resources

## 3.1 Technology Overview

Both Natural gas combustion turbines (CTG) and natural gas reciprocating engines (RICE) are commonly implemented technologies for utility scale power generation using pipeline natural gas as a fuel source.

Simple cycle combustion turbine plants are commonly used to supply peaking electric power due to their low capital cost, swift construction, quick starts and ability to operate cost effectively over a low range of capacity factors compared to other power generation facilities.

A combined cycle plant involves the addition of a heat recovery steam generator (HRSG) to the combustion turbine exhaust which provides steam to a steam turbine generator. The result is a significant increase in thermal efficiency over that of a simple cycle combustion turbine. Combined cycle plants offer key attributes of high efficiency, cost effective low emissions technology and relatively fast construction and startups beneficial to supplying base or intermediate load electric power.

Similar to simple cycle CT plants, simple cycle RICE installations are generally used to supply peaking power and to operate in load following scenarios. RICE technology is favorable for peaking applications due to its wide range of operability and rapid response capability. Generally, in utility power generation applications, RICE technology is smaller in scale and has better efficiency as compared to simple cycle CT technology. As compared to simple cycle CTs, RICE facilities are less susceptible to thermal performance variances due to changes in ambient conditions such as temperature and elevation.

The attributes of each natural gas resource evaluated are characterized as follows:

**Simple Cycle Aero Derivative Combustion Turbine Generator**

- 1 x 0 GE LMS 100 PA+ combustion turbine generator evaluated
- Water Injection for $NO_x$ Control
- Wet Cooled Intercooler w/ a mechanical draft cooling tower for heat rejection
- Selective Catalytic Reduction (SCR) and Oxidation Catalyst for $NO_x$ and CO emissions reduction
- Evaporative Cooling included
- Simple Cycle / Peaking Application
- Natural gas only fuel source

**Simple Cycle Frame Combustion Turbine Generator**

- 1 x 0 GE 7HA.02 combustion turbine generator evaluated
- Dry Low $NO_x$ Combustion Technology

- Selective Catalytic  Reduction (SCR) and Oxidation Catalyst for $NO_x$ and CO emissions reduction
- Evaporative Cooling included
- Simple Cycle / Peaking Application
- Natural gas only fuel source

**Combined Cycle Combustion Turbine Generator**

- 1 x 1 GE 7HA.02 combustion turbine generator configuration evaluated
- Dry Low $NO_x$ Combustion Technology
- Selective Catalytic  Reduction (SCR) and Oxidation Catalyst for $NO_x$ and CO emissions reduction
- Evaporative Cooling included
- Combined Cycle / Intermediate to Base Load Application
- Natural gas only fuel source
- Wet mechanical draft cooling tower with surface condenser
- Single shaft combustion turbine / steam turbine with common generator
- Triple pressure heat recovery steam generator w/ nominal 2400 psig, 1050 F / 1050 F main steam, reheat steam conditions

**Simple Cycle Reciprocating Engine Generators**

- 6 x 0 Wartsila 18V50SG  reciprocating engine generators evaluated
- Radiator / jacket water utilizes fin fans for heat rejection
- Selective Catalytic  Reduction (SCR) and Oxidation Catalyst for $NO_x$ and CO emissions reduction
- Simple Cycle / Peaking Application
- Natural gas only fuel source

## 3.2 Commercial Status

Natural gas CTG's and RICE technology are well proven and commercially available technologies for power generation. The major combustion turbine and RICE manufacturers all have significant experience throughout the world. RICE units generally range in size from 100 kW to 18 MW and current combustion turbines range in size from 1.5 MW to 370 MW.

## 3.3 Operational Considerations

### 3.3.1 Plant Performance

Overall estimated new and clean net plant output and net plant heat rate are depicted for each of the natural gas resource options in Table 3.3-1. The simple cycle RICE options plant performance is presented for a single unit in operation.

**Table 3.3-1. New and Clean Natural Gas Plant Performance**

| Thermal Cycle Performance | | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE (1 Unit) |
|---|---|---|---|---|---|
| **Summer, 90F, 100%** | | | | | |
| Net Output | kW | 92,005 | 346,920 | 506,547 | 18,241 |
| Net Heat Rate (HHV) | Btu/kWh | 9,042 | 9,212 | 6,258 | 8,485 |
| **Average, 55F, 100%** | | | | | |
| Net Output | kW | 95,553 | 355,630 | 517,016 | 18,241 |
| Net Heat Rate (HHV) | Btu/kWh | 8,930 | 9,135 | 6,232 | 8,453 |
| **Winter, 20 F, 100%** | | | | | |
| Net Output | kW | 96,829 | 377,334 | 540,487 | 18,241 |
| Net Heat Rate (HHV) | Btu/kWh | 8,882 | 9,022 | 6,237 | 8,440 |

Plant performance has also been developed at part load operating conditions from 100% load to minimum emission compliance load (MECL) for each of the natural gas resource options based on average life of plant degraded performance at ISO conditions of 59F, 60% humidity and 0 ft. elevation. Table 3.3-2 presents the unit turn down performance. The RICE performance is depicted for a single unit in operation and MECL has been depicted at approximately 30 percent load. Some engine manufactures have recently indicated the ability to turn down to 10 percent load while maintaining emission compliance, but performance data was not available at this operating point. Figure 3.3-1 further depicts plant performance as a function of load.

**Table 3.3-2. NG Plant Part Load ISO Performance, Average Life of Plant Degraded**

| Degraded Thermal Cycle Performance | | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE (1 Unit) |
|---|---|---|---|---|---|
| **ISO 100%** | | | | | |
| Net Output | kW | 92,525 | 344,522 | 500,248 | 17,997 |
| Net Heat Rate (HHV) | Btu/kWh | 9,113 | 9,310 | 6,362 | 8,537 |
| **ISO 75%** | | | | | |
| Net Output | kW | 69,231 | 259,089 | 395,752 | 13,381 |
| Net Heat Rate (HHV) | Btu/kWh | 9,682 | 10,114 | 6,580 | 9,011 |
| **ISO MECL** | | | | | |
| Net Output | kW | 47,057 | 105,747 | 199,687 | 5,141 |
| Net Heat Rate (HHV) | Btu/kWh | 11,060 | 14,368 | 7,595 | 11,209 |

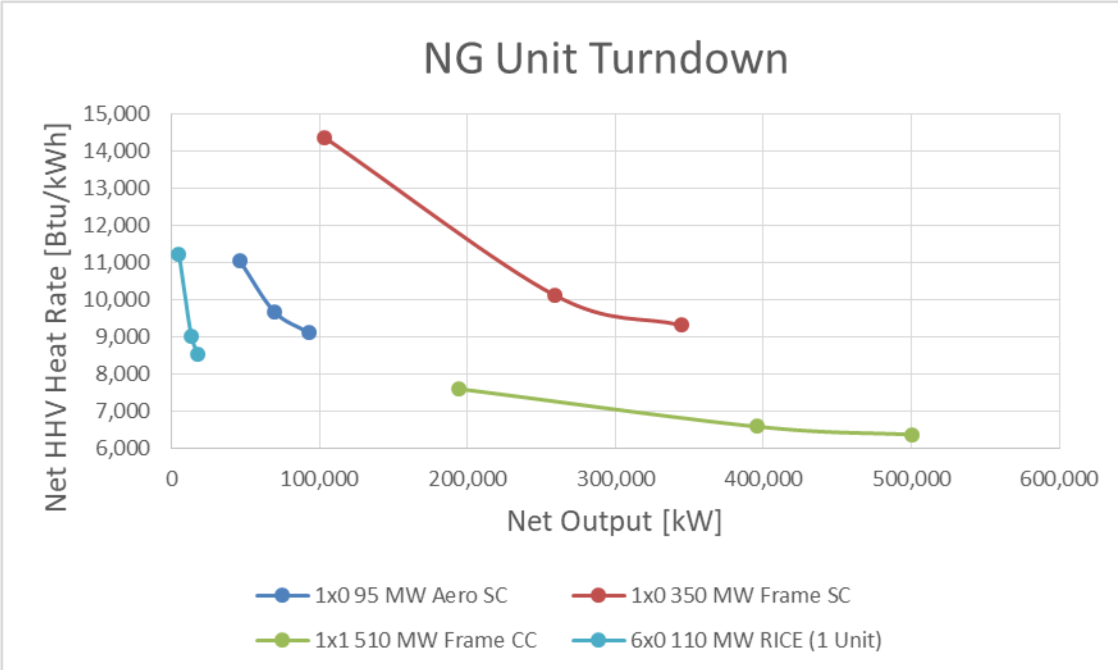


**Figure 3.3-1. NG Plant Part Load ISO Performance, Average Life of Plant Degraded**

### 3.3.2 Other Operating Characteristics

Other operating characteristics for the natural gas generation resources include ramp rate, minimum run times and minimum down times, and startup times. These are summarized for each natural gas resource in Table 3.3-3. The following assumptions and clarifications pertain to Table 3.3-3:

- Cold and warm start-up times are estimated from ignition to full plant load and assume the unit has been offline for more than 48 hours and 8 hours respectively. The combined cycle plant is designed for an emission compliant start such that the bottoming cycle is designed to allow for an unrestricted CTG start to MECL.
- Ramp rates depicted are for normal unit operation from MECL to full plant load and a single unit ramp rate is depicted for the RICE engine option.
- Minimum run times are representative of a typical 30 minute startup to full load and plant emission compliance. A 23 minute shutdown time from MECL to flameout for the CTG's and 1 minute shutdown for engines in addition to time to reduce from full load to minimum emission compliance load. It is possible to start the units and operate for shorter durations, but increased O&M costs may be incurred.
- An increased cold start maintenance factor may be incurred for some of the CTG options if started in under 1 hour.

**Table 3.3-3. NG Plant Miscellaneous Operating Characteristics.**

| | | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE (1 Unit) |
|---|---|---|---|---|---|
| Ramp rate | MW/min | 50 | 50 | 50 | 15.8 |
| Minimum run time | minutes | 60 | 60 | 60 | 35 |
| Minimum down time | minutes | 15 | 15 | 15 | 15 |
| Start-up time to full load at warm start | minutes | 10 | 21 | 60 | 5 |
| Start-up time to full load at cold start | minutes | 10 | 21 | 150 | 5 |

Startup fuel consumption for warm and cold starts has been estimated based on the startup times in Table 3.3-3. Table 3.3-4 summarizes estimated startup fuel, per start.

**Table 3.3-4. NG Plant Startup Fuel Requirements**

| Startup Fuel Consumption, per start | | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE (1 Unit) |
|---|---|---|---|---|---|
| Cold start fuel | MMBtu/start | 64 | 513 | 3,632 | 5.79 |
| Warm start fuel | MMBtu/start | 64 | 513 | 1,453 | 5.79 |

## 3.4 Reliability, Availability, & Maintenance Intervals

To address maintenance intervals for the natural gas generating resource options, typical industry degradation and outage intervals were used. Plant degradation for combustion turbine generators and reciprocating engine generators consists of recoverable and non-recoverable degradation. Recoverable degradation represents degradation that occurs between equipment maintenance intervals and can be recovered after completion of the maintenance. For CTG's, the maintenance intervals typically consist of:

- Offline and online compressors washes
- Hot gas path overhauls (25,000 factored fired hours), 15 day outage
- Major overhaul (50,000 factored fired hours), 25 day outage

For combined cycle plants, the steam turbine major overhauls typically coincide with the combustion turbine major overhauls. CTG overhaul intervals are based on factored fired hours, which can include fired operating hours and/or unit starts and stops.

For large reciprocating engine generators, the major equipment maintenance intervals occur as follows:

- Cylinder heads, gas system (18,000 fired hours), 8 day outage
- Valves, turbocharge, actuator (24,000 hours), 5 day outage
- Cylinder heads, vales, gas system, starting air distributor, vibration damper (36,000 hours), 14 day outage
- Valves, actuator (48,000 hours), 3 day outage

Expected average, life of plant degraded performance is summarized in Table 3.4-1 for each natural gas resource. The average life of plant performance is estimated based on expected plant degradation that will be experienced between maintenance cycles based identified above and the plant dispatch and capacity factors identified in Table 2.3-4. The RICE resource option performance is presented for a single unit.

**Table 3.4-1. Natural Gas Average Life of Plant Degraded Plant Performance**

| Degraded Thermal Cycle Performance | | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE (1 Unit) |
|---|---|---|---|---|---|
| **Summer 100%** | | | | | |
| Net Output | kW | 89,677 | 338,159 | 492,574 | 17,997 |
| Net Heat Rate (HHV) | Btu/kWh | 9,203 | 9,374 | 6,386 | 8,566 |
| **Average 100%** | | | | | |
| Net Output | kW | 93,087 | 346,591 | 502,611 | 17,997 |
| Net Heat Rate (HHV) | Btu/kWh | 9,094 | 9,298 | 6,362 | 8,534 |
| **Winter 100%** | | | | | |
| Net Output | kW | 94,313 | 367,602 | 524,931 | 17,997 |
| Net Heat Rate (HHV) | Btu/kWh | 9,047 | 9,186 | 6,372 | 8,520 |

To address reliability and availability for the various natural gas generation options, plant forced outage rates, planned outage rates, and mean average outage duration are summarized in Table 3.4-2. Plant forced outage rates are based on typical industry component forced outage rates. Componentes are generally broken down as combustion turbine, steam turbine, heat recovery steam generator, air quality control systems, and balance of plant equipment. Forced outage rates represent a full outage event. For the plant configurations considered, this would be typical as the prime equipment, such as the CTG's, are single units. In the case of the multi-unit RICE plant, partial forced outages may be incurred that would result in a reduced plant rating, but the forced outage rates presented are for a single RICE engine only (each unit would have the same forced outage rate). Multiplying a number of units by the forced outage rate will provide the partial forced outage rate for a given plant capacity with that many units out of service.

Planned outage rates are based on the maintenance schedules and durations identified above and the plant capacity factors identified in Table 2.3-4.

**Table 3.4-2. NG Plant Availbility/Reliability**

| Availability/Reliability | | 1x0 95 MW Aero SC | 1x0 350 MW Frame SC | 1x1 510 MW Frame CC | 6x0 110 MW RICE (1 Unit) |
|---|---|---|---|---|---|
| Forced Outage Rate | | 2.38% | 2.38% | 3.88% | 3.30% |
| Planned Outage Rate | | 1.73% | 1.73% | 2.19% | 1.84% |
| Mean Annual Outage Duration | days | 6.3 | 6.3 | 8.0 | 6.7 |

## 3.5 Other Performance Impacts

As a high level sensitivity, plant performance impacts have been estimated for differences in plant elevation as well as for dry cooling verse wet cooling heat rejection systems.

Plant Elevation Impacts:

- Plant output for a simple cycle plant can be expected to be reduced by approximately 1.5% for every 500 ft. of increased elevation. The plant heat rate of the turbine does not change significantly with elevation.
- For combined cycle plants, plant output is expected to be reduced approximately 1.5% on an average day and heat rate will increase 1.5% on an average day for every 500 ft. of elevation change.
- In comparison, the output and heat rate of RICE generators do not vary with elevation when below 5,000 feet of elevation.

Dry Cooling Heat Rejection System Impacts: Plant performance can be impacted by dry cooling heat rejection systems for both the combined cycle plant and the large aeroderivative CTG plant, which utilizes an intercooler system that must reject heat from the gas turbine compressor to the atmosphere.

For a combined cycle plant, typical plant performance impacts are:

- 2.5% decrease in output
- 2.5% increase in heat rate

For a large aeroderivative CTG simple cycle plant, use of a dry intercooler heat rejection system will result in the following approximate performance impacts:

- 1 to 2.5% decrease in output (average / summer day)
- 1.6 to 1.1% increase in heat rate (average / summer day)

## 3.6 Staffing Requirements

Staffing requirements to maintain full time operation of the facility have been developed for each thermal option. Required staff numbers are divided into hourly and salaried groups. For each technology, the number of staff required was assumed based on the plant configuration under consideration for the technology. Typical staffing levels for the simple cycle power plant are expected to be minimal as they are assumed to be located at an existing power generation facility and include:

- Two salaried staff
- One hourly staff

For combined cycle power plants considered, staffing levels are typically greater and include:

- Six salaried staff
- Eighteen hourly staff

## 3.7 Environmental Considerations

### 3.7.1 Emissions

Plant emissions rates and air quality control equipment assumed for each generation technology are those typically expected to be achievable and are representative of recent projects incorporating the same fuels and technologies. Emissions rates are provided on a lb/mmBtu heat input and lb/MWH basis. The emissions presented here are representative of controlled emissions at the discharge of the stack.

Air emissions for primary pollutants are presented in Table 3.7-1 for the various natural gas generating resource options. These rates are representative of limits which would be expected in an approved air permit for a project located in the Pacific Northwest.

**Table 3.7-1. NG Plant Expected Emissions**

| Plant Emissions | | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE (1 Unit) |
|---|---|---|---|---|---|
| NOx | **lb/mmbtu** | 0.0081 | 0.0081 | 0.0081 | 0.0203 |
| | **lb/MWH** | 0.073 | 0.075 | 0.051 | 0.172 |
| Particulate Matter PM10 Total | **lb/mmbtu** | 0.0057 | 0.0057 | 0.0057 | 0.0057 |
| | **lb/MWH** | 0.051 | 0.052 | 0.036 | 0.048 |
| SO2 | **lb/mmbtu** | 0.0014 | 0.0014 | 0.0014 | 0.0014 |
| | **lb/MWH** | 0.013 | 0.013 | 0.009 | 0.012 |
| CO | **lb/mmbtu** | 0.0123 | 0.0049 | 0.0049 | 0.0370 |
| | **lb/MWH** | 0.112 | 0.045 | 0.031 | 0.314 |
| VOC | **lb/mmbtu** | 0.0035 | 0.0014 | 0.0014 | 0.0351 |
| | **lb/MWH** | 0.032 | 0.013 | 0.009 | 0.298 |
| CO2 | **lb/mmbtu** | 118 | 118 | 118 | 118 |
| | **lb/MWH** | 1067 | 1087 | 738.5 | 1001 |

### 3.7.2 Water Consumption / Wastewater Discharge

For the thermal technologies, water consumption rates are estimated based on a rough conceptual design of the resource option and assume a blowdown discharge stream to a nearby water body or municipal sewer system. For the large aeroderivative simple cycle CTG and the combined cycle options, a wet cooling tower was assumed for heat rejection. Table 3.7-2 summarizes water consumption and wastewater discharge for each generation option. These rates are based on the assumption that the facility design incorporates recycling and reuse of water to the greatest extent possible.

**Table 3.7-2. NG Plant Water Consumption and Discharge**

| Water Consumption | | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE (1 Unit) |
|---|---|---|---|---|---|
| **Summer** | | | | | |
| Total Water Consumption | gal/MWH | 175 | 10.2 | 251 | 0.822 |
| Waste Water Discharge | gal/MWH | 40.7 | 2.07 | 50.4 | 0.822 |
| **Average** | | | | | |
| Total Water Consumption | gal/MWH | 148 | 0.042 | 183 | 0.137 |
| Waste Water Discharge | gal/MWH | 29.6 | 0.042 | 36.7 | 0.137 |

## 3.8 Land Requirements

Land requirements for each of the natural gas generating technologies are summarized in Table 3.8-1. The land requirements represent the area within the plant fence and assume utility interconnections for fuel, electrical transmission, water, and wastewater discharge occur at the site boundary. Land requirements for the RICE engine plant are for a six (6) engine plant size.

**Table 3.8-1. NG Plant Land Requirements**

| | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE |
|---|---|---|---|---|
| **Length, ft** | 500 | 680 | 800 | 420 |
| **Width, ft** | 380 | 400 | 470 | 360 |
| **Area, Acres** | 4.4 | 6.2 | 8.6 | 3.5 |

## 3.9 Project Cost

Table 3.9-1 summarizes the estimated total project costs for each of the natural gas thermal resources considered for a 2018 notice to proceed. The breakdown of estimated EPC costs and estimated Owner's costs are also shown for reference. The calculated standard deviation from the total overnight plant cost and the estimated end of plant life decommissioning costs are also referenced.

**Table 3.9-1. Natural Gas Plant Project EPC and Owner's Costs (Total Plant)**

| Project Costs (2018 US $) | | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE (1 Unit) |
|---|---|---|---|---|---|
| Total Plant Cost | $1,000 | $ 110,184 | $ 188,976 | $ 468,486 | $ 138,427 |
| Total Plant Cost | $/kW | $ 1,154 | $ 531 | $ 906 | $ 1,265 |
| EPC Plant Cost | $1,000 | $ 95,091 | $ 162,327 | $ 404,333 | $ 119,469 |
| Owner's Cost | $1,000 | $ 15,093 | $ 26,649 | $ 64,154 | $ 18,958 |
| | | | | | |
| Std Deviation from Total Plant Costs | $/kW | $ 311 | $ 143 | $ 244 | $ 341 |
| | | | | | |
| End of Life Decomissioning Costs | $1,000 | $ 1,100 | $ 1,600 | $ 2,500 | $ 3,200 |

Total plant cost ($/kW) values are based on the plant new and clean net average day output.

## 3.10 Implementation (Schedule)

The estimated project schedules for the natural gas generating resource options are based upon current day EPC contracting approaches and methodologies. As such, for the natural gas fired facilities, it is expected that a significant portion of preliminary engineering and equipment sourcing activities are completed prior to the FNTP of the project. This will typically involve the procurement of major equipment and of the EPC contract with some level of LNTP awarded for these contracts prior to an FNTP. Figures 3.10-1, 3.10-2, 3.10-3, and 3.10-4 summarize a typical project implementation schedule for an aeroderivative simple cycle CTG, frame simple cycle CTG, RICE, and a combined cycle project from NTP to COD.

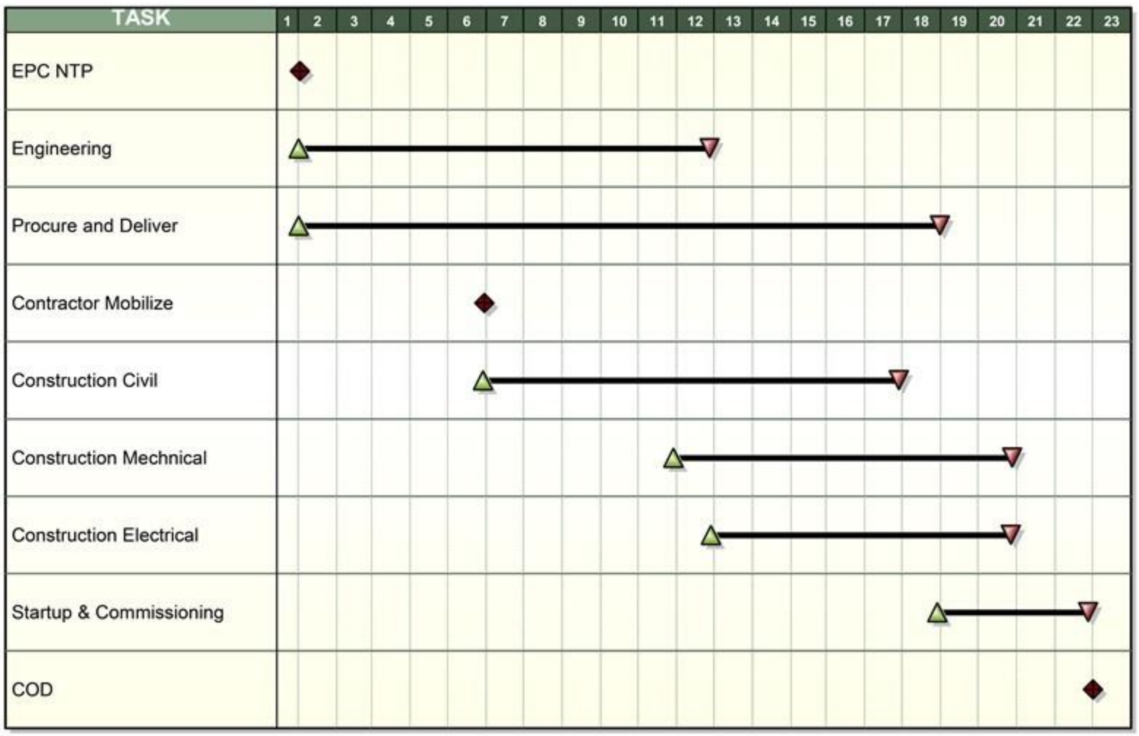


**Figure 3.10-1. 1x0 95 MW Aero SC Conceptual Project Schedule.**

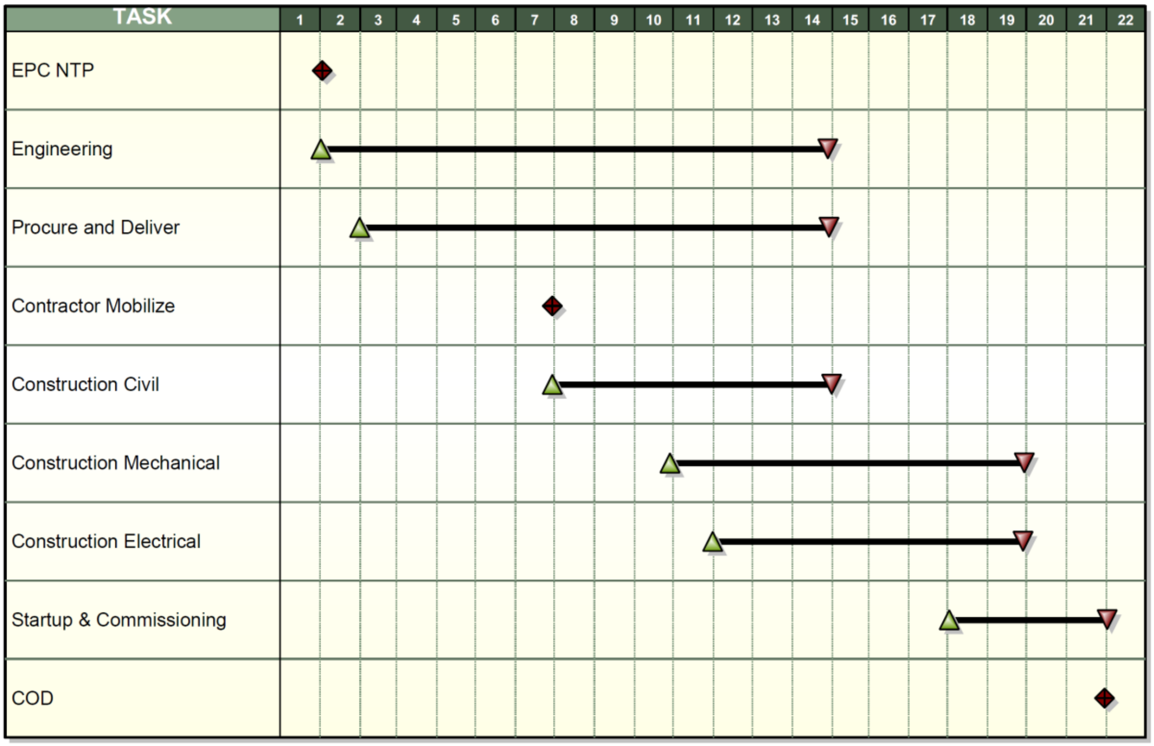


**Figure 3.10-2. 1x0 350 MW Frame SC Conceptual Project Schedule**

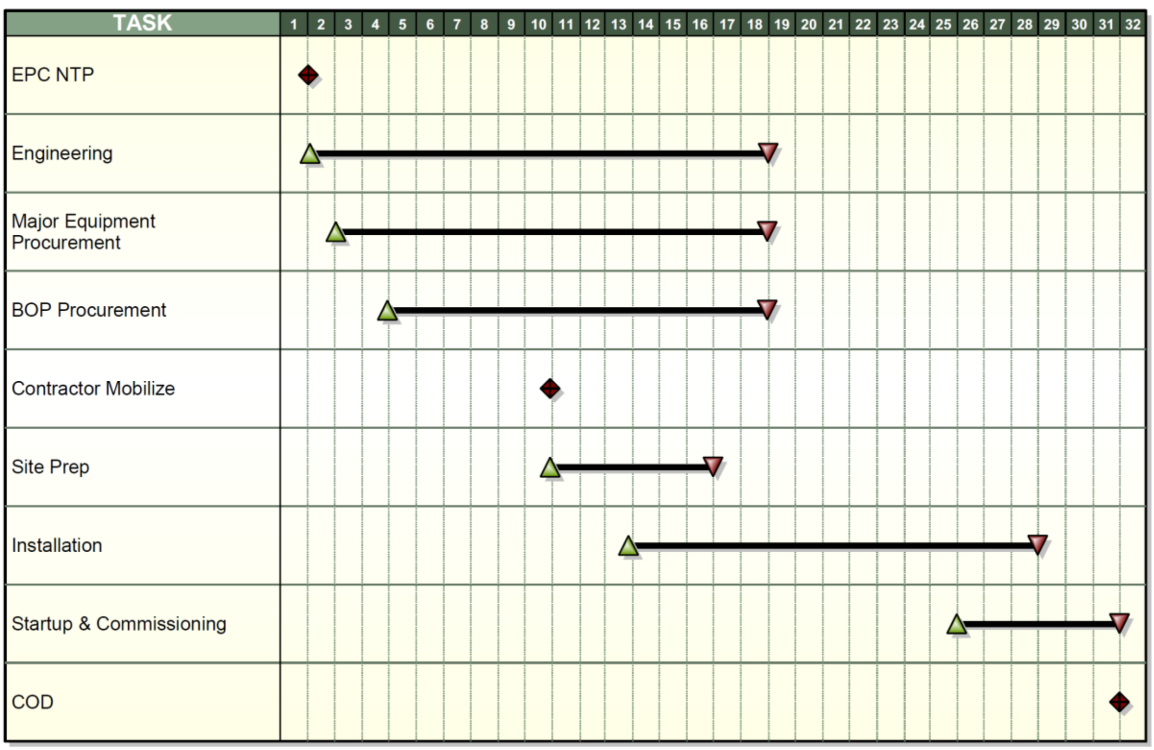


**Figure 3.10-3. 1x1 510 MW Frame Combined Cycle Conceptual Project Schedule.**

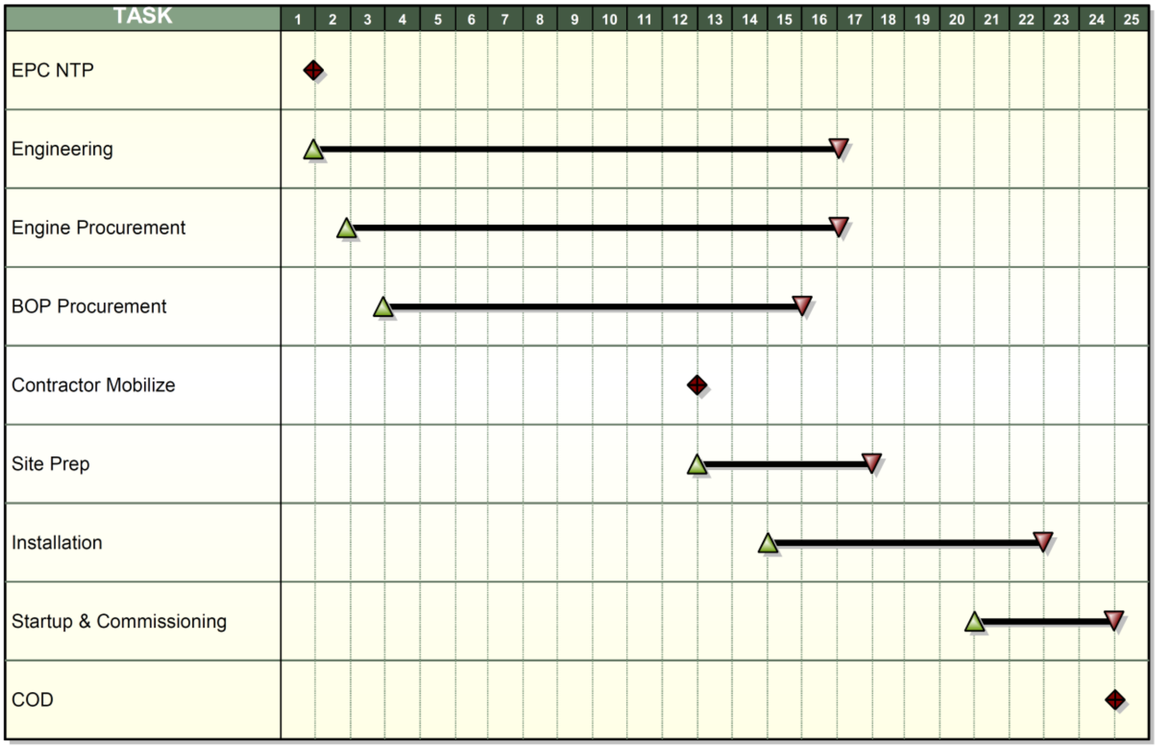


**Figure 3.10-4. 6x0 110 MW RICE Conceptual Project Schedule.**

## 3.11 Operating Costs

The estimated fixed and variable O&M costs for each natural gas technology are presented in Table 3.11-1. Simple cycle CTG and RICE options assumed a peaking dispatch profile and intermediate load dispatch profile as identified in Table 2.3-4.

Operation and maintenance costs are also inclusive of gas turbine long term maintenance contract, steam turbine, HRSG, and balance of plant equipment costs, spare parts inventory, and other consumable costs including aqueous ammonia, water, and water discharge. Startup fuel and land lease costs are not included. Plant staffing has been included as defined in Section 3.6.

**Table 3.11-1. NG Plant Fixed and Variable Operating Costs**

| Operating Costs, 2018 $, Degraded | | 1x0 96 MW Aero SC | 1x0 356 MW Frame SC | 1x1 517 MW Frame CC | 6x0 109 MW RICE (1 Unit) |
|---|---|---|---|---|---|
| **Summer** | | | | | |
| Fixed O&M | $/kW-yr | 5.61 | 2.10 | 6.57 | 5.15 |
| Variable O&M | $/MWH | 5.20 | 9.69 | 3.57 | 5.42 |

Additional breakdown of the O&M costs are included in the modeling input tabs in Appendix E.

# 4 Biomass Steam Generation Resource

Biomass power production is derivative from traditional solid fuel power plants in that a large boiler is used to combust fuel and generate steam that then drives a turbine to produce electricity. Many different suitable fuel sources exit for combustion in a biomass power plant. The main fuel sources for solid biomass plants are wood or other agricultural byproducts such as shells or husks. Biomass plants have also been constructed to burn solid waste from garbage and fuels derived from used automobile tires. The viability of a biomass plant is generally dependent on the availability of a nearby source of biomass waste to be burned in the plant's boiler. For the purpose of this study a 30 MW wood burning biomass steam plant has been considered with the following features:

**30 MW Biomass Steam Plant**

- Circulating fluidized bed (CFB) steam generator
- Single Pressure, non-reheat steam cycle
- Selective non-catalytic reduction for $NO_x$ emissions
- Fabric filter for particulate matter emissions
- Woody biomass fuel source, delivered to site by truck
- Wet mechanical draft cooling tower with surface condenser

## 4.1 Technology Overview

Biomass plants operate based on the traditional Rankine cycle that governs the operation of coal fired steam power plants. A biomass fuel, such as wood chips, is burned in a large boiler or steam generator. This steam is then piped at high pressure to the inlet of steam turbine to turn the generator and produce electric power. The steam exhausted from the outlet of the turbine is sent to a condenser where it is returned to its liquid state to be cycled back into the boiler. Biomass plants generally employ fluidized bed boiler technology either with a bubbling fluidized bed (BFB) or a circulating fluidized bed boiler (CFB). Other boiler types such as stoker boilers can also be considered. Ultimately the choice of boiler for a biomass installation is dependent on the desired output and the intended fuel. For the purpose of this analysis, a CFB type boiler was considered. This was paired with a single stage steam turbine and a water cooled condenser using a wet cooling tower. Boiler technology for these plants traditionally consisted of stoker type boilers. A bubbling bed boiler (BFB) or circulating fluidized bed (CFB) boiler is more commonly used today and can achieve lower emissions, though. For the purpose of this evaluation, a CFB boiler has been assumed.

## 4.2 Commercial Status and Current Market

Biomass power production is well developed and commercially available method of developing electric power. The technologies implemented in biomass power plants are heavily adapted from solid fuel coal plants which have a long history of operation in the United States. The major limiting factor for the implementation of a biomass plant is the availability of a suitable fuel source. Generally, a large quantity of economical nearby biomass fuel is required to allow the installation of a biomass facility. Despite these restrictions, there are currently approximately

16.8 GW of installed biomass capacity in the United States alone[6]. Biomass power plants currently installed in the United States range from less than 5 MW of output up to 150 MW of output.

## 4.3 Operational Considerations

### 4.3.1 Plant Performance

Overall estimated new and clean net plant outputs and net plant heat rates are depicted for a 30 MW CFB biomass plant in Table 4.3-1.

**Table 4.3-1. 30 MW Biomass Power Plant New and Clean Performance**

| Thermal Cycle Performance | | 30 MW Biomass |
|---|---|---|
| **Summer 100%** | | |
| Net Output | kW | 29,985 |
| Net Heat Rate (HHV) | Btu/kWh | 13,653 |
| **Average 100%** | | |
| Net Output | kW | 30,478 |
| Net Heat Rate (HHV) | Btu/kWh | 13,450 |
| **Winter 100%** | | |
| Net Output | kW | 30,731 |
| Net Heat Rate (HHV) | Btu/kWh | 13,354 |

As part of this analysis, heat rate curves for unit turn down from 100% load to MECL operation were generated for the biomass plant based on operation at ISO conditions of 59F, 60% humidity and 0 ft. elevation. Table 4.3-2 below tabulates the turn down performance used to generate the heat rate curves. Figure 4.3-1 further depicts plant performance as a function of load.

[6] Statista, www.statista.com

**Table 4.3-2. 30 MW Biomass Plant Part Load ISO Performance, Average Life of Plant Degraded**

| Degraded Thermal Cycle Performance | | 30 MW Biomass |
|---|---|---|
| **ISO 100%** | | |
| Net Output | kW | 30,278 |
| Net Heat Rate (HHV) | Btu/kWh | 13,753 |
| **ISO 75%** | | |
| Net Output | kW | 22,274 |
| Net Heat Rate (HHV) | Btu/kWh | 14,021 |
| **ISO MECL** | | |
| Net Output | kW | 13,932 |
| Net Heat Rate (HHV) | Btu/kWh | 15,000 |

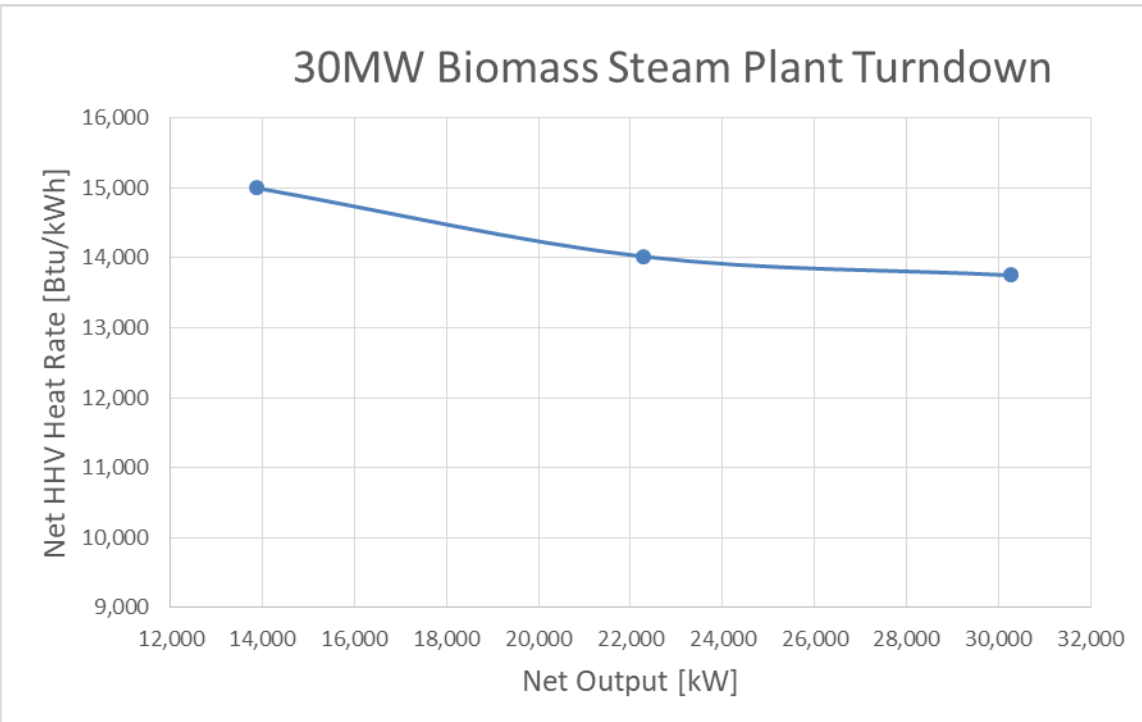


**Figure 4.3-1. 30 MW Biomass Plant Part Load ISO Performance, Average Life of Plant Degraded**

### 4.3.2 Other performance Characteristics

Other operating characteristics of the biomass steam generation resource includes ramp rate, minimum run times, minimum down times, and startup times. These characteristics are summarized for a 30 MW biomass steam generation resource in Table 4.3-3. The following assumptions and clarifications pertain to Table 4.3-3:

- Cold and warm start-up times assume the unit has been offline for more than 48 hours and 8 hours respectively and are from ignition to full steam turbine load.
- Ramp rates depicted are for normal unit operation from MECL to full plant load for a typical steam turbine generator.
- Minimum run times and down times are typical recommended run times for modeling purposes and may vary based on Owner operating preferences.

**Table 4.3-3. Biomass Plant Miscellaneous Operating Characteristics**

| | | 30 MW Biomass |
|---|---|---|
| Ramp rate | MW/min | 2 |
| Minimum run time | minutes | 240 |
| Minimum down time | minutes | 60 |
| Start-up time to full load at warm start | minutes | 240 |
| Start-up time to full load at cold start | minutes | 720 |

Startup fuel consumption for warm and cold starts has been estimated based on the startup times in Table 4.3-3. Table 4.3-4 summarizes estimated startup fuel, per start. Natural gas or oil is typically used for startup fuel.

**Table 4.3-3. Biomass Plant Startup Fuel Requirements**

| Startup Fuel Consumption, per start | | 30 MW Biomass |
|---|---|---|
| Cold start fuel | MMBtu/start | 2,050 |
| Warm start fuel | MMBtu/start | 683 |

## 4.4 Reliability, Availability, & Maintenance Intervals

Plant degradation for a biomass plant consists primarily of degradation from the bottoming cycle, including the steam turbine generator performance. Expected average, life of plant degraded performance is summarized in Table 4.4-1 for a 30 MW biomass steam plant. The average life of plant performance is estimated based on typical industry degradation and outage intervals that will be experienced between maintenance cycles based on a 60,000 hour steam turbine overhaul schedule and the plant dispatch and capacity factors identified Table 2.3-4

**Table 4.4-1. 30 MW Biomass Plant Average Life of Plant Degraded Plant Performance**

| Degraded Thermal Cycle Performance | | 30 MW Biomass |
|---|---|---|
| **Summer 100%** | | |
| Net Output | kW | 29,985 |
| Net Heat Rate (HHV) | Btu/kWh | 13,887 |
| **Average 100%** | | |
| Net Output | kW | 30,363 |
| Net Heat Rate (HHV) | Btu/kWh | 13,731 |
| **Winter 100%** | | |
| Net Output | kW | 30,527 |
| Net Heat Rate (HHV) | Btu/kWh | 13,673 |

To address reliability and availability for a biomass steam generation plant, forced outage rates, planned outage rates, and mean average outage duration is summarized in Table 4.4-2. Plant forced outage rates are based on typical industry component forced outage rates. Componentes were generally broken down as and include the steam generator/boiler, STG, AQCS, and balance of plant equipment. Planned outage rates assume a 14 day annual outage most years and a longer 56 day outage corresponding with a steam turbine overhaul every 60,000 operating hours.

**Table 4.4-2. 30 MW Biomass Plant Plant Availbility/Reliability**

| Availability/Reliability | | 30 MW Biomass |
|---|---|---|
| Forced Outage Rate | | 3.07% |
| Planned Outage Rate | | 6.03% |
| Mean Annual Outage Duration | days | 22 |

## 4.5 Environmental Considerations

### 4.5.1 Emissions

The expected emissions for the 30 MW biomass plant after all applicable emissions control equipment are depicted in Table 4.5-1. It is expected that the plant would utilize selective non-catalytic reduction (SNCR) for the mitigation of $NO_x$ emissions and a boiler bed limestone injection for the mitigation $SO_2$ emissions as required. A baghouse is included for control of particulate emissions. The emissions presented here are based on the biomass fuel composition described in section 2. Actual emissions can vary depending on the final composition of the biomass fuel selected.

### Figure 4.5-1. 30 MW Biomass Emissions

| Plant Emissions | | 30 MW Biomass |
|---|---|---|
| Plant Heat Input (Summer), HHV | mmbtu/hr | 409 |
| Plant Net Output (Summer) | MW | 30 |
| NOx | lb/mmbtu | 0.0290 |
| | lb/MWH | 0.396 |
| Particulate Matter PM10 Total | lb/mmbtu | 0.0540 |
| | lb/MWH | 0.737 |
| SO2 | lb/mmbtu | 0.0320 |
| | lb/MWH | 0.437 |
| CO | lb/mmbtu | 0.30 |
| | lb/MWH | 4.096 |
| VOC | lb/mmbtu | 0.0351 |
| | lb/MWH | 0.480 |
| CO2 | lb/mmbtu | 213 |
| | lb/MWH | 2904 |

### 4.5.2 Water Consumption / Wastewater Discharge

The main water user for the 30 MW biomass plant considered in this analysis is the wet cooling tower used to supply cooling water to the condenser. The plant will also require a certain amount of makeup water to supplement flow lost in the steam drum blow down. Expected makeup and discharge water flows for the plant are summarized in Table 4.5-2.

### Table 4.5-2. Biomass Plant Water Consumption

| Water Consumption | | 30 MW Biomass |
|---|---|---|
| **Summer** | | |
| Total Water Consumption | gal/MWH | 851 |
| Waste Water Discharge | gal/MWH | 170 |
| **Average** | | |
| Total Water Consumption | gal/MWH | 650 |
| Waste Water Discharge | gal/MWH | 130 |

## 4.6 Land Requirements

Land requirements for a biomass steam generating technology are summarized in Table 4.6-1. The land requirements represent the area within the plant fence and assume utility interconnections for fuel, electrical transmission, water, and wastewater discharge occur at the site boundary.

**Table 4.6-1. 30 MW Biomass Plant Land Requirements**

| | 30 MW Biomass |
|---|---|
| Length, ft | 740 |
| Width, ft | 560 |
| Area, Acres | 9.5 |

## 4.7 Project Cost

Table 4.7-1 summarizes the estimated total project costs for a 30 MW biomass steam plant. The breakdown of estimated EPC cost and estimated Owner's costs are also shown for reference. The calculated standard deviation from the total overnight plant cost and the estimated end of plant life decommissioning costs are also referenced.

**Table 4.7-1. Biomass Plant EPC and Owner's Costs**

| Project Costs (2018 US $) | | 30 MW Biomass |
|---|---|---|
| Total Plant Cost | $1,000 | $ 180,199 |
| Total Plant Cost | $/kW | $ 5,935 |
| EPC Plant Cost | $1,000 | $ 155,511 |
| Owner's Cost | $1,000 | $ 24,688 |
| | | |
| Std Deviation from Total Plant Costs | $/kW | $ 1,599 |
| | | |
| End of Life Decomissioning Costs | $1,000 | $ 4,166 |

Total plant cost ($/kW) values are based on the plant new and clean net average day output.

## 4.8 Implementation Schedule

The estimated project schedules for a 30 MW biomass steam generating plant are based upon current day contracting approaches and methodologies. Similar to the natural gas resource options, it is expected that a significant portion of preliminary engineering and equipment sourcing activities are completed prior to the FNTP of the project. A 30 MW CFB biomass plant can be expected to take 3 to 4 years to construct from the time of EPC notice to proceed to the final commercial operation date. Figure 4.8-1 below depicts a typical implementation schedule and depicts the major milestones of the project from NTP to COD.

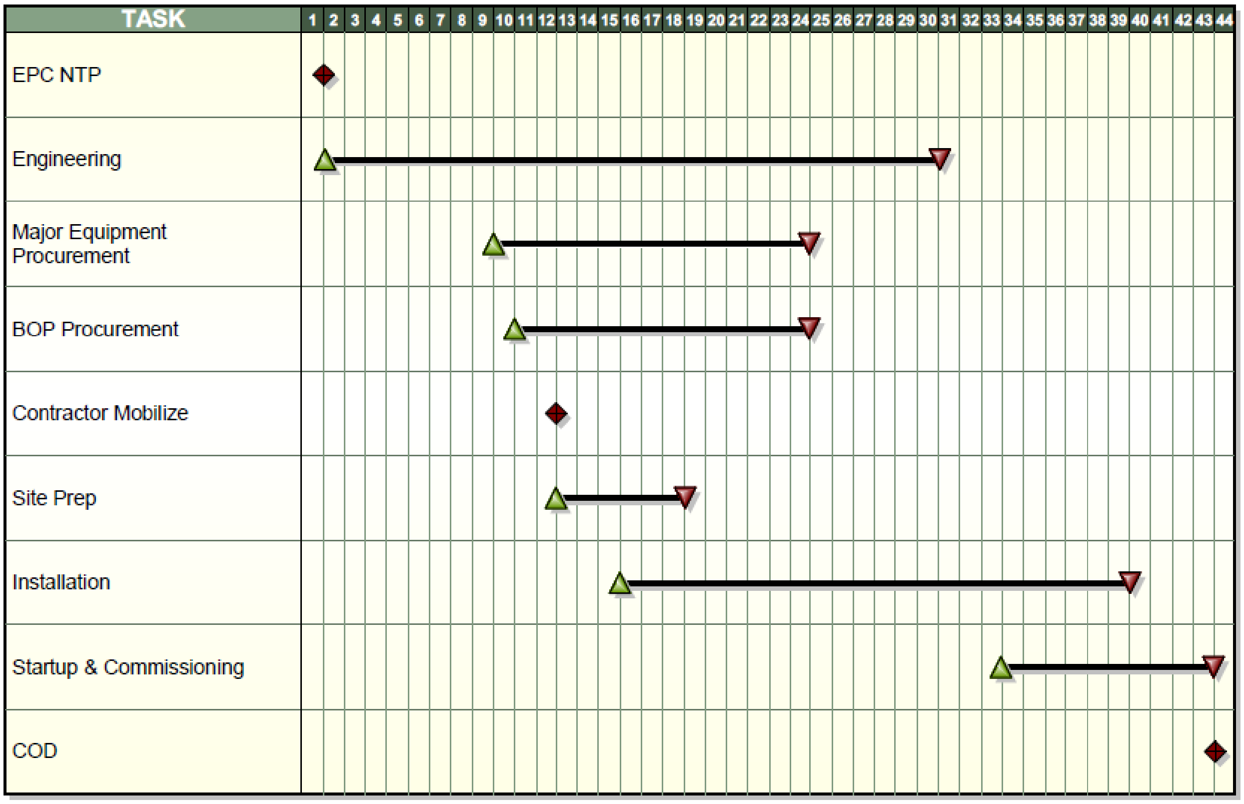


**Figure 4.8-1. 30 MW Biomass Conceptual Project Schedule.**

## 4.9 Operating Costs

The estimate fixed and variable O&M costs for a 30 MW biomass plant is summarized in Table 4.9-1. A base load dispatch profile has been assumed.

Operation and maintenance costs are also inclusive of steam generator, steam turbine, HRSG, and balance of plant equipment costs, spare parts inventory, and other consumable costs including aqueous ammonia, water makeup, and water discharge.  Startup fuel is not included.

Staffing requirements to maintain full time operation of the facility have been developed for a 30 MW biomass power plant is estimated to include:

- Nine (9) salaried staff
- Nineteen (19) hourly staff

**Table 4.9-1 Fixed and Variable Operating Costs**

| Operating Costs, 2018 $, Degraded | | 30 MW Biomass |
|---|---|---|
| **Summer** | | |
| Fixed O&M | $/kW-yr | 111 |
| Variable O&M | $/MWH | 5.28 |

Additional detail and breakdown of O&M costs are included in the modeling input tabs in Appendix E.

# 5 Geothermal Generation Resource

Geothermal Power is similar to other turbine power stations in that heat from a fuel source is used to heat water or another working fluid. The working fluid is then used to turn a turbine. For Geothermal Power the heat is from the thermal energy stored in the Earth's crust. High temperature thermal reservoirs are the most beneficial for utility-scale electricity production, but are geologically limited to locations where geothermal pressure reserves are found. For the purpose of this study, a 30 MW geothermal flash plant was assumed viable in the Pacific Northwest. The characteristics of the geothermal generation technology evaluated are further defined as follows:

**30 MW Geothermal Plant**

- Flash Steam Plant Evaluated
- Wet mechanical draft cooling tower with surface condenser

## 5.1 Technology Overview

Geothermal energy consists of the thermal energy stored in the Earth's crust. Reservoirs of geothermal energy are generally classified as being either low temperature (<300°F) or high temperature (>300°F). Figures 5.1-1 and 5.1-2 provide geothermal maps that estimate the geothermal fluid temperatures at 3 km and 6 km depth.

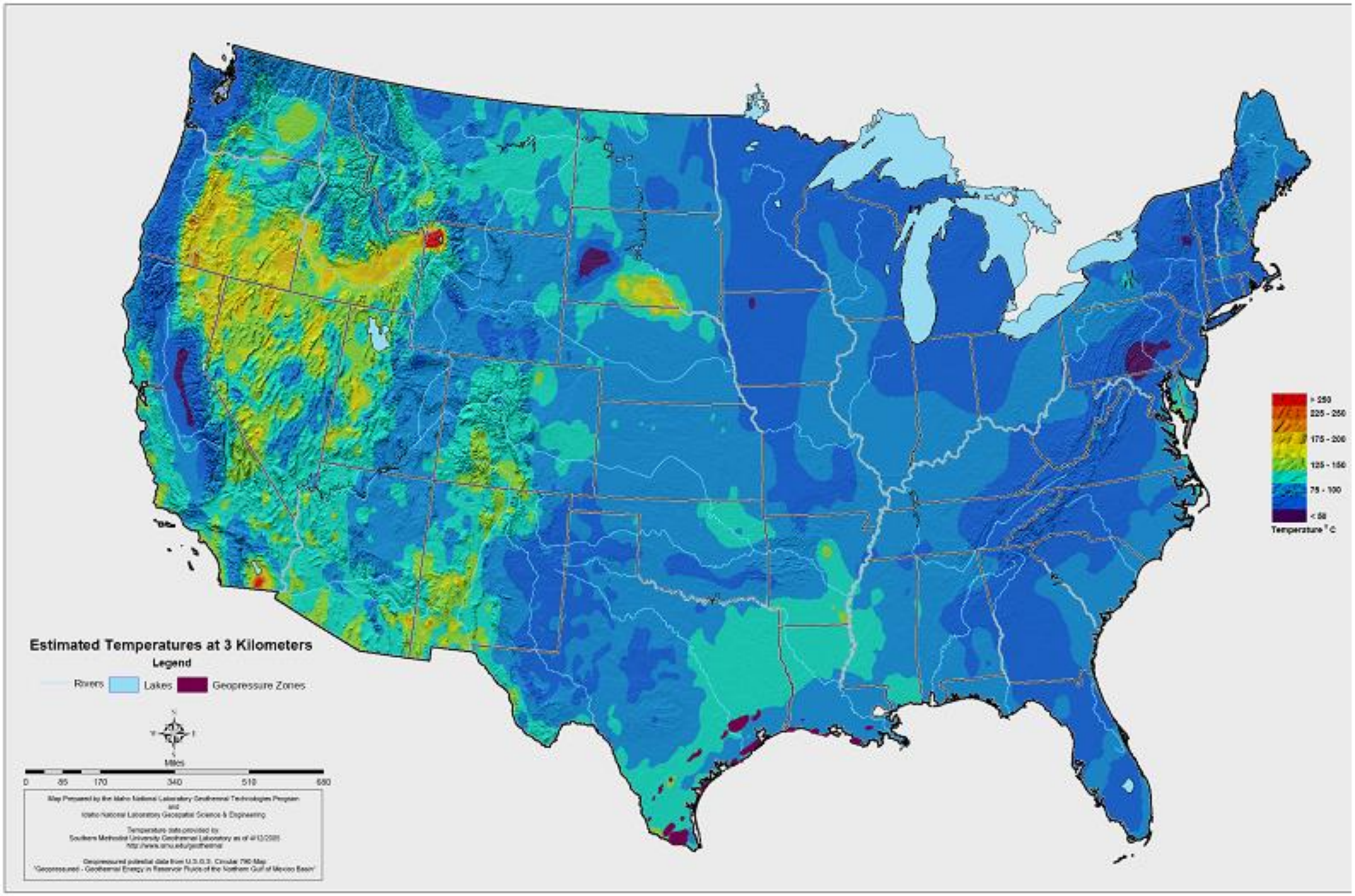


**Figure 5.1-1. US Geothermal Map Estimating Earth Temperature at 3 kilometers.**

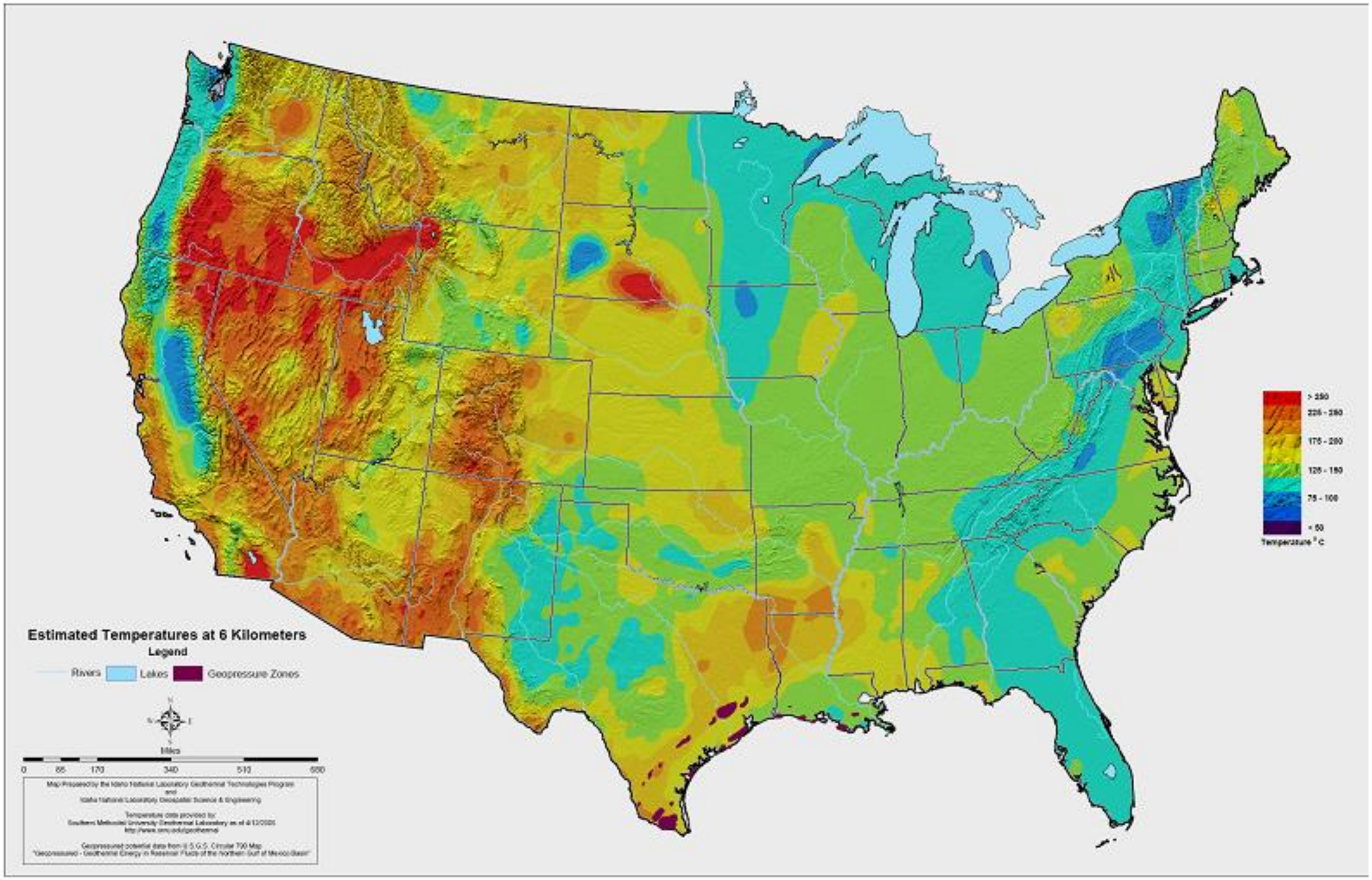


**Figure 5.1-2. US Geothermal Map Estimating Earth Temperature at 6 kilometers.**

High temperature reservoirs are the most beneficial for commercial production of electricity. Currently, three types of geothermal power plants are commercially developed: dry steam, flash steam, and the binary cycle.

Dry steam power plants were the first type of geothermal technologies designed and implemented. Dry steam power plants extract steam from geothermal reservoirs within the Earth's crust where it is piped directly into a steam turbine generator for electric power production. The steam turbine exhaust flow is condensed and injected back into the geothermal reservoir to be reheated.

Flash steam geothermal power plants utilize hot water from geothermal reservoirs that flows up through wells within the Earth's crust under its own pressure. Temperatures of hot water from the flash steam reservoirs are typically greater than 360°F. The free flowing, hot, pressurized water flows upward, decreasing in pressure until some of the hot water boils into steam. The steam is separated from the water and expanded through a steam turbine generator for electric power production. The steam is then condensed and mixed with the hot water that did not flash and is injected back into the reservoir to regain heat energy, completing this cyclical sustainable resource. Flash steam power plants also install pumps where necessary to pump the hot water out of the Earth's surface. Once reaching the surface, the hot water pressure is suddenly reduced allowing some of the water to flash into steam. Flash steam power plants are the most common geothermal power plants.

Binary cycle power plants also utilize water from the Earth's crust similar to flash steam power plants. However, the water temperatures are considerably lower than water used for flash steam plants. Typical water temperatures range from 225°F to 360°F. Binary cycle plants implement a non-contact heat exchanger to extract heat from the hot water to vaporize the working fluid (usually an organic compound with a low boiling point). Once the working fluid is vaporized it is expanded through a turbine. The water is then injected back into the ground to be reheated. Binary cycle geothermal power plants are more efficient than flash steam geothermal plants.

## 5.2 Commercial Status and Current Market

Geothermal power plants are well proven and commercially available technologies for power generation. There has been vast implementation of geothermal power facilities throughout the world. Long-term sustainable geothermal power production has been demonstrated at the Lardarello field in Italy since 1913, at the Wairakei field in New Zealand since 1958, and at The Geysers field in California since 1960.

Geothermal heat extraction is similar to extraction processes utilized for the oil and gas, coal, and mining industries. Equipment, knowledge and techniques have been adapted and implemented for use in geothermal development taken from the industries mentioned above, therefore the equipment and technology exists commercially to drill into geothermal reservoirs or permeable rock.

Currently there is approximately 14 GW of installed geothermal capacity globally with an estimated 18 GW of capacity that will be installed by 2021. Of the different types of technologies typically utilized, flash technology represents approximately 60 percent of the installed capacity, dry steam technology represents 25 percent of the installed capacity, and binary cycle plant technology is utilized in the remaining plants[7].

## 5.3 Operational Considerations

Geothermal power stations have much in common with traditional power generating stations. They use many of the same components, including turbines, generators, transformers, and other standard power generating equipment, but also include a pumping and re-injection system.

The primary risk associated with geothermal power generation technology is the integrity of the geothermal energy source and of the geothermal wells constructed for the recovery of this energy. The longevity of a geothermal facility is primarily a function of the geothermal energy source. Some installations may require the drilling of additional wells over the life of the project to continue the supply of energy.

### 5.3.1 Performance Data

Overall estimated new and clean net plant output is depicted for a 30 MW geothermal plant in Table 5.3-1 at average day conditions.

**Table 5.3-1. New and Clean 30 MW Geothermal Plant Performance**

| **Thermal Cycle Performance** | | **30 MW Geo-thermal** |
|---|---|---|
| **Average 100%** | | |
| Net Output | kW | 30,000 |
| Net Heat Rate (HHV) | Btu/kWh | NA |

Table 5.3-2 summarizes the expected plant performance at turn down from 100% to minimum plant load.

[7] 2016 US & Global Geothermal Power Production Report, Geothermal Energy Association

**Table 5.3-2. 30 MW Geothermal Plant ISO Part Load Performance, Average Life of Plant Degraded**

| Degraded Thermal Cycle Performance | | 30 MW Geo-thermal |
|---|---|---|
| **ISO 100%** | | |
| Net Output | kW | 22,787 |
| Net Heat Rate (HHV) | Btu/kWh | NA |
| **ISO 75%** | | |
| Net Output | kW | 17,090 |
| Net Heat Rate (HHV) | Btu/kWh | NA |
| **ISO MECL** | | |
| Net Output | kW | 7,500 |
| Net Heat Rate (HHV) | Btu/kWh | NA |

### 5.3.2 Other performance Characteristics

Other operating characteristics include ramp rate, minimum run times, minimum down times, and startup times. These parameters are summarized for a 30 MW geothermal plant in Table 5.3-3.

- Cold and warm start-up times assume the unit has been offline for more than 48 hours and 8 hours respectively and are reflective of a typical steam turbine and steam generator ramp rate profile for these conditions.
- Ramp rates depicted are for normal unit operation from MECL to full plant load for a typical steam turbine generator.
- Minimum run times and down ties are typical recommended run times for modeling purposes and may vary based on Owner operating preferences.

**Table 5.3-3. Biomass Plant Miscellaneous Operating Characteristics.**

| | | 30 MW Geo-thermal |
|---|---|---|
| Ramp rate | MW/min | 2 |
| Minimum run time | minutes | 240 |
| Minimum down time | minutes | 60 |
| Start-up time to full load at warm start | minutes | 60 |
| Start-up time to full load at cold start | minutes | 420 |

## 5.4 Reliability, Availability, & Maintenance Intervals

Plant degradation for a geothermal plant consists primarily of loss in well production over time, scaling that may occur within equipment from the geothermal fluid deposits, and degradation from the bottoming cycle, including the steam turbine generator performance. Expected average, life of plant degraded performance is summarize in Table 5.4-1 for a 30 MW geothermal plant based on an estimated well head performance degradation over time and variation in well head production annually. No new wells are assumed to be developed over the project life or water injected into wells to replenish the wells. Consistency of well head production for geothermal projects can vary from site to site.

**Table 5.4-1. 30 MW Geothermal Plant Average Life of Plant Degraded Plant Performance**

| Degraded Thermal Cycle Performance | | 30 MW Geo-thermal |
|---|---|---|
| **Average 100%** | | |
| Net Output | kW | 23 |
| Net Heat Rate (HHV) | Btu/kWh | NA |

To address reliability and availability for a geothermal generation plant, forced outage rates, planned outage rates, and mean average outage duration is summarized in Table 5.4-2. Plant forced outage rates are based on typical industry component forced outage rates for a steam plant. Forced outage rates and plant availability statistics for geothermal plants vary greatly and due to differences in maintenance practices and well head production. Components include the steam generator/boiler, STG, balance of plant equipment and well gathering field equipment. Plant forced outage rates, planned outage rates, and mean average outage duration is summarized in Table 5.4-2. Planned outage rates are based on a 14 day annual outage annually and a 56 day outage corresonding with a 60,000 hour steam turbine overhaul schedule for a base load facility.

**Table 5.4-2. 30 MW Geothermal Plant Availbility/Reliability**

| Availability/Reliability | | 30 MW Geo-thermal |
|---|---|---|
| Forced Outage Rate | | 3.04% |
| Planned Outage Rate | | 4.93% |
| Mean Annual Outage Duration | days | 18.0 |

## 5.5 Environmental Considerations

### 5.5.1 Emissions

There are negligible air emissions for the proposed geothermal power plant.

### 5.5.2 Water Consumption / Wastewater Discharge

Flash steam plants typically use wet mechanical draft cooling towers for heat rejection from the condenser of the steam turbine generator and other balance of plant systems. The makeup water to the cooling tower typically is assumed to be supplied from the geothermal wells and therefore external water requirements are expected to be minimal. Cooling tower blowdown is assumed to be injected into the geothermal reinjection wells.

## 5.6 Land Requirement

Land requirements for a 30 MW geothermal plant are summarized in Table 5.6-1 and include the wells (and required spacing), gathering field, and power plant. Land well field area is assumed to be approximately 225 acres per well and includes production wells, injection wells, and an allowance for failed wells and exploratory drilling. Total well count is approximately 13 to 14. The actual geothermal power plant land requirement is expected to be 5 to 10 acres. All land is assumed to be purchased and is included in the Owner's costs.

**Table 5.6-1. 30 MW Geothermal Land Requirements**

| | 30 MW Geo-thermal |
|---|---|
| **Length, ft** | - |
| **Width, ft** | - |
| **Area, Acres** | 3,000 |

## 5.7 Capital Cost

Table 5.7-1 summarizes the estimated total project costs for a 30 MW geothermal plant. The breakdown of estimated EPC cost and estimated Owner's costs are also shown for reference.

Approximately 39 million dollars (2018$) for well field development prior to FNTP is also included in the Owner's costs. These well field development costs should not be used in the draw down schedule provided in Appendix D.

The calculated standard deviation from the total overnight plant cost and the estimated end of plant life decommissioning costs are also referenced.

**Table 5.7-1. Geothermal Plant Project Costs**

| **Project Costs (2018 US $)** | | **30 MW Geo-thermal** | |
|---|---|---|---|
| Total Plant Cost | $1,000 | $ | 186,927 |
| Total Plant Cost | $/kW | $ | 6,216 |
| EPC Plant Cost | $1,000 | $ | 116,751 |
| Owner's Cost | $1,000 | $ | 70,176 |
| | | | |
| Std Deviation from Total Plant Costs | $/kW | $ | 1,215 |
| | | | |
| End of Life Decomissioning Costs | $1,000 | $ | 1,862 |

Total plant cost ($/kW) values are based on the plant new and clean net average day output.

## 5.8 Implementation Schedule

The estimated project schedule for a geothermal generating resource option is based upon current day contracting approaches and methodologies. Geothermal power plants typically have a timeline of 3 years from a notice to proceed for drilling and equipment and construction contracts through Commercial Operation. The steam turbine generator would be the piece of equipment with the longest lead time estimated to be approximately 20 months. In the past, the main issue of concern for implementing a geothermal power plant has been the difficulty in permitting and leasing geothermal lands, which can lead to long development timeframes prior to project notice to proceed (two to three years or more can be expected). Figure 5.8-1 summarizes a typical project implementation schedule for a 30 MW geothermal installation from NTP to COD. The schedule assumes the bidding of major equipment and of the EPC contract with some level of limited notice to proceed awarded for these contracts prior to an FNTP.

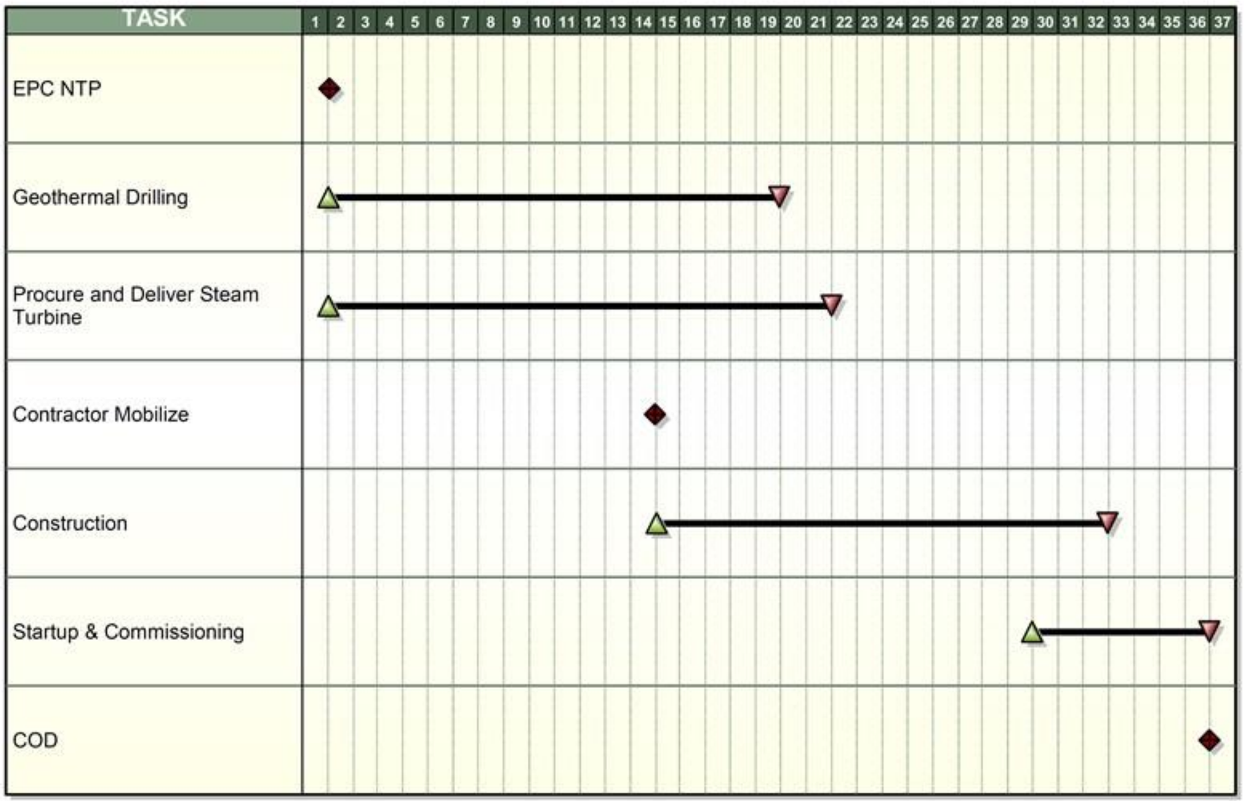


**Figure 5.8-1. Geothermal Conceptual Project Schedule**

## 5.9 Operating Costs

The estimate fixed and variable O&M costs for a 30 MW geothermal plant are summarized in Table 5.9-1. A base load dispatch profile has been assumed. Land is assumed to be purchased and is included in Owner’s costs.

Staffing requirements to maintain full time operation of the facility have been developed for a 30 MW geothermal power plant and are estimated to include:

- Nine (9) salaried staff
- Nineteen (19) hourly staff

Operating and maintenance costs also include steam turbine, boiler/flash plant, and balance of plant maintenance as well as well and gathering field maintenance costs.

### Table 5.9-1 Geothermal Fixed and Variable Operating Costs

| Operating Costs, 2018 $, Degraded | | 30 MW Geo-thermal |
|---|---|---|
| **Summer** | | |
| Fixed O&M | $/kW | 120 |
| Variable O&M | $/MWH | 2.39 |

Additional detail and breakdown of O&M costs are included in the modeling input tabs in Appendix E.

# 6 Pumped Hydro Energy Storage Resource

Pumped hydro is an energy storage technology that mimics the operation of a hydroelectric power plant. A typical station consists of two reservoirs separated in elevation. At times of high energy demand when excess energy is needed, water is released from the upper reservoir through a turbine to produce electric. At night or during other periods of low electric demand, cheaper off peak electricity is supplied to pump water back from the lower reservoir to the high reservoir. Pumped hydro storage facilities can achieve maximum outputs greater than 2,000 MW.

The following attributes characterize the pumped hydro energy storage project considered:

**1,200 MW Pumped Hydro Energy Storage (PHES)**

- 3 x 400 MW nominal, variable speed, closed loop system evaluated
- 8 Hour discharge duration / reservoir storage capacity
- Average Static Head: 2,900 ft.

## 6.1 Technology Overview

Pumped hydro stations generate electricity by releasing water from a reservoir at a high elevation to flow downward through a water turbine into another reservoir. These plants differ from conventional hydroelectric plants in that the process can be reversed and the water pumped back to the higher elevation reservoir and stored to be released at a later time. In most pumped hydro installations these two processes are accomplished by a single reversible pump-turbine which can both generate electricity when operating as a turbine and also pump water when electricity is fed to the generator and the turbine is used as a pump. Modern pumped hydro facilities take advantage of variable speed pump-turbines to give the operators greater dispatch flexibility. Overall, pumped hydro facilities are net consumers of electricity. In other words it requires more electricity to pump the water up to the higher reservoir than is generated when the water is released to produce electricity. This is due to net process losses and auxiliary loads that are required for the operation of the plant in lieu of generating resources. For this reason, pumped hydro facilities are considered to be energy storage assets. Pumped hydro facilities require the presence of either natural occurring or man-made bodies of water. These water bodies are generally very large.

## 6.2 Commercial Status and Current Market

Pumped hydro storage is the most mature energy storage technology in today's power industry market. The first U.S. pumped-storage plant was developed in the 1920s to balance loads from fossil fuel plants within a very nascent grid. A typical pumped storage plant is designed for more than 50 years of service life, but many projects that were constructed in the 1920's and 1930's are still operational today. The lifecycle of pumped hydro facility is comparable to that of a traditional hydroelectric facility. Similar to other rotating power technologies, a generator-motor rewind or upgrade can be expected after approximately 20 years of service, with the pump-turbine equipment lasting for a longer period of time with routine maintenance. Today, there are approximately 40 pumped storage projects operating in the United States that provide more than 20 GW of capacity[8].

## 6.3 Operational Considerations

### 6.3.1 Performance Data

The performance and operating characteristics for a 1,200 MW closed loop, variable speed pumped hydro facility are presented in Table 6.3-1.

**Table 6.3-1. 1,200 MW Pumped Hydro Performance Characteristics**

| 1200 MW Pumped Hydro Performance and Operational Characteristics | | |
|---|---|---|
| Capacity | MW | 1200 |
| Storage Duration | hrs | 8 |
| Average Storage Head | ft. | 2,900 |
| | | |
| Number of Turbine/Pump Units | | 3 |
| | | |
| Average Plant Turnaround Efficiency | | 80% |
| | | |
| Generation Mode (per unit) | | |
| At minimum head | | |
| Min MW | | 183 |
| Max MW | | 366 |
| At maximum head | | |
| Min MW | | 111 |
| Max MW | | 400 |
| | | |
| Pumping Mode (per unit) | | |
| At minimum head | | |
| Min MW | | 354 |
| Max MW | | 517 |
| At maximum head | | |
| Min MW | | 401 |
| Max MW | | 517 |

[8] Energy Storage Association, www.energystorage.org

### 6.3.2 Other performance Characteristics

Other operating characteristics of a modern, variable speed pumped hydro energy storage, including ramp rate, minimum run times and minimum down times, and startup times are summarized in Table 6.3-2.

**Table 6.3-2. 1,200 MW Pumped Hydro Plant Miscellaneous Operating Characteristics.**

| | | 1200 MW Pumped Hydro (1 Unit) |
|---|---|---|
| Ramp rate | MW/min | 255 |
| Minimum run time | minutes | 0 |
| Minimum down time | minutes | 0 |
| Start-up time to full load at warm start | minutes | 2 |
| Start-up time to full load at cold start | minutes | 2 |

Typical time for a modern plant to switch between pumping and generation modes of operation is also approximately 3 minutes.

## 6.4 Reliability, Availability, & Maintenance Intervals

Estimated plant forced outage rates, planned outage rates, and mean average outage duration are summarized in Table 6.4-1 for a single 400 MW unit of the 1,200 MW pumped hydro storage plant.

**Table 6.4-1. 1,200 MW Pumped Hydro Storage Plant Availbility/Reliability**

| Availability/Reliability | | 1200 MW Pumped Hydro (1 Unit) |
|---|---|---|
| Forced Outage Rate | | 1.00% |
| Planned Outage Rate | | 3.84% |
| Mean Annual Outage Duration | days | 14 |

## 6.5 Environmental Considerations

### 6.5.1 Emissions

Pumped hydroelectric energy storage facilities generally have no associated air, water, or solid byproduct discharges or emissions.

### 6.5.2 Water Consumption / Wastewater Discharge

No makeup water costs for pumped energy storage have been included in this analysis. There is also no discharge water.

## 6.6 Land Requirement

Land costs for a pumped hydro storage plant must include both the upper and lower resevoirs as well as the upper and lower connecting tunnels. For a 1200 MW nonminal project with 8 hours of storage, or roughly 4,800 acre-ft of water storage capacity, total land requirements are estimated at approximately 1000 acres. The land purchase costs are included as part of the Owner's costs in the project costs.

## 6.7 Capital Cost

Table 6.7-1 presents the estimated total project costs for a 1,200 MW pumped hydro storage plant with 8 hours of storage capacity. Estimated EPC cost and estimated Owner's costs are broken out from total project costs for reference. Owner's costs for pumped hydro storage are estimated at approximately 20 percent of total project costs as development costs are typically higher and with longer timeframes.

The calculated standard deviation from the total overnight plant cost and the end of plant life decommissioning costs are also referenced.

**Table 6.7-1. 1,200 MW Pumped Hydro Storage Costs**

| Project Costs (2018 US $) | | 1200 MW Pumped Hydro |
|---|---|---|
| Total Plant Cost | $1,000 | $ 2,701,984 |
| Total Plant Cost | $/kW | $ 2,252 |
| EPC Plant Cost | $1,000 | $ 2,160,000 |
| Owner's Cost | $1,000 | $ 541,984 |
| | | |
| Std Deviation from Total Plant Costs | $/kW | $ 587 |
| | | |
| End of Life Decomissioning Costs | $1,000 | $ 25,870 |

Total plant cost ($/kW) values are based on the plant new and clean net average day output.

## 6.8 Schedule

The schedule for the development and construction of a pumped hydro energy storage plant can vary considerably depending on a number of factors, including the amount of civil work required to construct the water storage basins and the permitting required to implement the project. Based on historical information, the total construction time from receipt of Federal Energy Regulatory Commission (FERC) license to commercial operation can be anywhere from 5 years to 8 years for projects similar to that evaluated herein.

## 6.9 Operating Costs

The estimate fixed and variable O&M costs for a 1200 MW pumped hydro plant are summarized in Table 6.7-1. Operating costs do not include electric purchases during pumping. Pumping costs are determined by dividing the dispatched plant load by the average plant turnaround efficiency of 80% and multiplying by the cost of electricity.

Staffing requirements to maintain full time operation of the facility is estimated to include:

- Six (6) salaried staff

- Twenty-eight (28) hourly staff.

O&M costs are inclusive of turbine, generator, and balance of plant and facility routine maintenance and major overhaul costs. Land purchases are included as part of Owner's costs in the project costs.

**Table 6.7-1. Pumped Hydro Storage Fixed and Variable Operating Costs**

| Operating Costs, 2018 $, Degraded | | 1200 MW Pumped Hydro |
|---|---|---|
| **Summer** | | |
| Fixed O&M | $/kW | 11.3 |
| Variable O&M | $/MWH | 0.372 |

# Appendices