GENERIC RESOURCE COSTS

FOR

INTEGRATED RESOURCE PLANNING

Revision: 4

Puget Sound Energy

HDR Project No. 10111615

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Executive Summary

Puget Sound Energy (PSE) is preparing its 2019 integrated resource plan (IRP) for Washington State, which includes an evaluation of thermal, renewable, and energy storage technologies as potential supply-side resource alternatives. HDR Engineering, Inc. (HDR) was retained by PSE to assist with the overall 2019 IRP effort by characterizing the operational and cost attributes of various power generation and energy storage technologies. This information is intended to support modeling and portfolio optimization as a means of evaluating and comparing strategies for the 2019 IRP. The parameters developed for each technology include estimated performance and operating characteristics, capital costs, operating costs, and implementation schedules. The range of technologies considered includes several natural gas-fired and dual fueled thermal generation options, renewable technologies, and energy storage technologies. The resulting parameters for the various technologies are summarized in Table E-1 for representative project sites. The following summarizes the basis for development of the parameters for each of the technologies:

- Performance has been estimated for all options based on supplier feedback, representative site conditions, and performance estimating software.
- Conceptual level project capital costs have been developed based on an overnight, turnkey engineer, procure, construct (EPC) delivery in 2018 dollars.
- An opinion of probable owner's cost is identified separately for each technology, and typically includes costs associated with project development, permitting, contracting, owner's engineering support, etc.
- PSE's estimate of AFUDC allocation as a percentage of option specific EPC costs.
- Potential future cost trends of the technologies considered are included to understand potential impacts of technology maturity to capital costs over time.
- 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.
- 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; associated project cash flow curves are also included.
- Input parameters for dispatch modeling were derived from the O&M costs and various operating characteristics were developed for each option.

Additional details and results regarding the development of the IRP inputs are further summarized in this report. The inputs and 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

Puget Sound Energy 2019 IRP	Fuel	Winter Peak Net Output	Winter Peak Net Heat Rate[1] (HHV)	EPC Cost[2]	Owner's Cost[2]	Total Cost[2]	Capacity Factor[3]	First Year Fixed O&M	First Year Variable O&M	EPC Schedule	Gas + Electric Interconnent	Total with Interconnect
Unit Type	**Type**	**MW**	**Btu/kWh**	**$/kW**	**$/kW**	**$/kW**	**%**	**$/kW-yr**	**$/MWh**	**Months**	**$/kW**	**$/kW**
Simple Cycle (SC) Combustion Turbine (CT)												
1x0 F-Class Dual Fuel CT (NG / FO)[4]	NG	237	9,774	$554	$131	$686	4%	$3.93	$6.56	20 - 22	$139	$825
1x0 F-Class Dual Fuel CT (NG / FO)[4]	FO	229	9,900									
Combined Cycle (CC) CT - Wet Cooling												
1x1 F-Class CC (Unfired)	NG	348	6,649	$898	$232	$1,131	85%	$14.16	$2.52	30 - 32	$99	$1,229
1x1 F-Class CC (Fired)	NG	367	6,761	$853	$221	$1,073	85%	$13.44	$2.45	30 - 32	$94	$1,167
Reciprocating Internal Combustion Engine (RICE)												
12x0 18 MW Class RICE (NG Only)	NG	219	8,428	$842	$201	$1,043	15%	$3.74	$5.30	26 - 28	$148	$1,192
12x0 18 MW Class Dual Fuel RICE (NG / FO)[4]	NG	201	8,565	$965	$230	$1,196	15%	$4.12	$5.80	26 - 28	$161	$1,357
12x0 18 MW Class Dual Fuel RICE (NG / FO)[4]	FO	173	8,763									
On-Shore Wind												
100 MW Wind Farm - Central Montana (Sites #1 and #3)[5]	-	100	-	$1,410	$226	$1,636	36%/46%	$37.00	-	20 - 24	$86	$1,722
100 MW Wind Farm - Central Montana (Site #2)[5]	-	100	-	$1,410	$226	$1,636	42%	$37.00	-	20 - 24	$576	$2,212
100 MW Wind Farm - Southeast Washington (Site #4)	-	100	-	$1,420	$227	$1,647	32%	$37.00	-	20 - 24	$103	$1,749
300 MW Wind Farm - Central Montana (Sites #1 and #3)[5]	-	300	-	$1,354	$217	$1,570	36%/46%	$37.00	-	20 - 26	$46	$1,617
300 MW Wind Farm - Central Montana (Site #2)[5]	-	300	-	$1,354	$217	$1,570	42%	$37.00	-	20 - 26	$231	$1,802
300 MW Wind Farm - Southeast Washington (Site #4)	-	300	-	$1,366	$219	$1,585	32%	$37.00	-	20 - 26	$49	$1,633
Off-Shore Wind												
300 MW Wind Farm - Washington Coast	-	300	-	$5,000	$1,480	$6,480	31-35%	$120.00	-	33 - 40	$67	$6,547
Solar Photovoltaic (PV)												
25 MW Solar PV (Washington) - Single Axis Tracking	-	25	-	$1,352	$191	$1,543	24%	$27.19	-	10 - 12	$380	$1,922
100 MW Solar PV (Washington) - Single Axis Tracking	-	100	-	$1,338	$174	$1,512	24%	$21.20	-	10 - 12	$103	$1,614
Biomass												
15 MW Biomass	Wood	15	14,154	$7,036	$2,031	$9,067	85%	$345.20	$6.60	38 - 40	$628	$9,695
Pumped Hydro Energy Storage (PHES)[6]												
PHES - 500 MW Closed Loop (8 Hour)	Elec. Grid	500	-	$1,800	$812	$2,612	-	$14.55	$0.90	60 - 96	$49	$2,661
PHES - 300 MW Closed Loop (8 Hour)	Elec. Grid	300	-	$1,800	$812	$2,612	-	$17.40	$1.50	60 - 96	$67	$2,679
Battery Energy Storage System (BESS)												
BESS - 25 MW Lithium Ion (2 Hour / 2 Cycles Daily)	Elec. Grid	25	-	$1,331	$219	$1,550	-	$20.54	-	10 - 12	$380	$1,930
BESS - 25 MW Lithium Ion (4 Hour / 2 Cycles Daily)	Elec. Grid	25	-	$2,346	$334	$2,680	-	$32.16	-	10 - 12	$380	$3,059
BESS - 25 MW Vandium Flow (4 Hour / 2 Cycles Daily)	Elec. Grid	25	-	$1,493	$239	$1,732	-	$30.80	-	10 - 12	$380	$2,111
BESS - 25 MW Vandium Flow (6 Hour / 2 Cycles Daily)	Elec. Grid	25	-	$2,050	$328	$2,378	-	$40.27	-	10 - 12	$380	$2,758

1 Thermal heat rates are presented on a higher heating value (HHV) basis.
2 $/kW capital cost metrics divide estimated project costs by the winter peak net output for a given technology. An AFUDC allocation is included in Owner's Costs. .
3 Capacity factors for dispatchable technologies assumed in order to develop O&M costs.
4 Project costs for dual fuel configurations include dual fuel systems and equipment; O&M costs indicated are based on limited backup fuel oil (FO) firing.
5 Montana wind Site #1 represents a site in close proximity to the Colstrip transmission line. Montana wind Site #2 represents a site near Great Falls, Montana. Montana Site #3 is assumed to be located in eastern Montana and is assumed to interconnect to the local transmission system.
6 PHES considers a "slice" of a larger PHES project development in the Pacific Northwest US.

1. Introduction

Puget Sound Energy (PSE) is preparing its 2019 electric integrated resource plan (IRP) for Washington State. PSE is evaluating several types of supply-side resources including thermal, renewable, and energy storage technologies. HDR Engineering, Inc. (HDR) was retained by PSE to assist with the characterization of the power generation and energy storage technologies considered in the IRP planning work. This evaluation focuses on supply-side alternatives, with PSE considering demand-side alternatives separately. These characterizations resulted in the development of modeling parameters and assumptions intended to be used in further portfolio modeling and evaluation for PSE's 2019 IRP. Technology characteristics presented include estimated performance and operating characteristics, capital costs, operations and maintenance (O&M) costs, and implementation schedules for several natural gas-fired generating technologies, renewable technologies, and energy storage options. This report summarizes the assumptions utilized and basis of approach to develop the characteristics for each technology. In addition, information on current market conditions that may influence the accuracy of the parameters or impact the ability of PSE to implement the technologies considered is also discussed.

1.1. Resource Options

The following power generation and energy storage resource options were considered.

- 1x0 Simple Cycle (SC) Combustion Turbine (CT)
    - Dual fuel F-class unit considered (natural gas with fuel oil as secondary fuel)
- 1x1 Combined Cycle (CC) CT
    - Natural gas fuel only F-class CT with heat recovery steam generator (HRSG) supplemental duct firing capability
    - Wet, mechanical draft cooling for heat rejection
- 12x0 SC Reciprocating Internal Combustion Engine (RICE)
    - 18 MW (large) class RICE considered
    - Natural gas only configuration
    - Dual fuel configuration – natural gas with fuel oil as secondary fuel
- On-Shore Wind
    - Nominal 100 MW and 300 MW wind farms
    - Three sites in Montana
    - One site in Washington
- Off-Shore Wind
    - Nominal 300 MW wind farm
    - Assumed to be located approximately 3 miles off of Washington coast with fixed platforms
- Solar Photovoltaic (PV)
    - Nominal 25 MW (AC) and 100 MW (AC) solar PV facilities
    - Single axis tracking configuration in Washington State
- Biomass
    - Nominal 15 MW station with woody biomass as the primary fuel source

- Pumped Hydro Energy Storage (PHES)
  - 300 MW with 8 hours of storage
  - 500 MW with 8 hours of storage
  - Assumes slice of larger project in Pacific Northwest United States
- Battery Energy Storage System (BESS)
  - 25 MW lithium ion (Li-ion) with 2 and 4 hours of storage
  - 25 MW vanadium flow with 4 and 6 hours of storage
  - 2 discharge cycles per day considered

1.2. Acronyms

The following acronyms are listed for reference and are used throughout this report.

Term	Definition
AC	Alternating current
AFUDC	Allowance for Funds Used During Construction
ASHRAE	American Society of Heating, Refrigeration, and Air-Conditioning Engineers
BESS	Battery energy storage system
Btu	British thermal units
CC	Combined cycle
CO	Carbon monoxide
CO_2	Carbon dioxide
COD	Commercial operation date
CT	Combustion turbine
DC	Direct current
EIA	Energy Information Administration
EPC	Engineer, Procure, Construct
FERC	Federal Energy Regulatory Commission
G&A	General and administrative (costs)
GSU	Generator step-up (transformer)
HHV	Higher heating value
HRSG	Heat recovery steam generator

IDC	Interest During Construction
IRP	Integrated resource plan/planning
kW	Kilowatt
LHV	Lower heating value
Li-ion	Lithium ion (battery technology)
mmBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt-hour
NCF	Net capacity factor
NO_x	Oxides of nitrogen
NREL	National Renewable Energy Laboratory
NTP	Notice to Proceed
O&M	Operations and maintenance
OEM	Original equipment manufacturer
PHES	Pumped hydro energy storage
PM	Particulate matter
ppm	Parts per million
PSE	Puget Sound Energy
PV	Photovoltaic (solar technology)
RICE	Reciprocating internal combustion engine
RFP	Request for proposals
SC	Simple cycle
SCR	Selective catalytic reduction
SU&C	Startup and commissioning
SEIA	Solar Energy Industries Association

2. Study Basis, Assumptions, and Supplemental Information

The purpose of this study is to develop conceptual operational and cost attributes for a variety of generation and storage technologies. As the technologies evaluated in IRP activities are not project-, location-, or technology supplier-specific, development of the technology attributes is based on a variety of generic inputs and assumptions and is focused on being representative of current market offerings. This Section provides the overall basis and assumptions considered in developing technology characteristics, and also includes discussion pertaining to supplemental information including representative project cash flows and potential future cost trends of resources. The discussion in this Section is supplemented with additional specific considerations in the technology Sections following.

2.1. Site Characteristics

The following proxy site locations were assumed based on the technologies considered:

- Natural gas-fired, biomass, and BESS technologies – site conditions consistent with PSE's Fredrickson site[7]
- Solar PV – A generic site in Yakima, Washington
- On-Shore Wind – Three sites in Montana and one site in southeastern Washington[8]
- Off-shore Wind – Multiple sites considered off the coast of Washington State
- PHES – Assumed as a slice of a larger, new development in the Pacific Northwest

Summer peak, summer average, winter peak, and winter average ambient conditions for the proxy PSE Fredrickson site were determined based on ASHRAE 2017 climate data. These ambient conditions as well as the assumed site elevation are summarized in Table 2.1-1 below.

Table 2.1-1. Assumed Site Conditions for PSE's Frederickson Site

Site Conditions		Summer (Peak)	Summer (Average)	Winter (Average)	Winter (Peak)
Site Elevation	ft. AMSL	322			
Dry Bulb Temperature	deg F	88.0	65.0	40.0	23.0
Wet Bulb Temperature	deg F	65.7	42.1	35.6	20.4
Relative Humidity	%	30.0%	30.0%	65.0%	65.0%

[7] PSE's Frederickson site considered for proxy site conditions (elevation, climate data) only; technology attributes intended to represent generic sites in the Pacific Northwest US and does not represent an in-progress project.
[8] Two sites in Montana were considered based on proximity to the Colstrip transmission line and a third focused on identifying a higher wind resource area connected to the local transmission system.

2.2. Technology Suppliers

This evaluation considers generic technology types and size classes in order to provide a representation of the current supplier marketplace. The performance and cost characteristics developed for this effort consider feedback from suppliers (through budgetary data and technical discussion), publicly available information, and data and information from previous developments and projects. The performance and cost characteristics consider a variety of supplier inputs, are intended to be representative, and are not intended to suggest a specific technology supplier is preferred by PSE over another. Many capable suppliers exist for a given technology and, if a given technology were developed, suppliers would be vetted through a competitive request for proposal (RFP) process.

2.3. Plant Performance

2.3.1. Performance

Plant performance (i.e. output, efficiency, etc.) was estimated for all technologies based on performance estimating software, previous project developments, feedback from 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 development of facility auxiliary loads. Performance was developed for summer and winter day ambient conditions at full and part load operating conditions.

For the wind and solar technologies, estimated net capacity factors (NCFs) were developed utilizing performance estimating software made available by the National Renewable Energy Laboratory (NREL). Performance for other alternatives was estimated based on feedback from suppliers, current marketplace benchmarking, and previous project developments.

2.3.2. Air Emissions

For the thermal and biomass 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. Air emissions for other technologies are expected to be minimal.

2.3.3. Water Resources

Plant water consumption and wastewater discharge was estimated for the thermal and biomass technologies based on conceptual plant water management systems typical of the technology evaluated.

An allocation is included in the O&M costs for panel wash water for the solar PV alternatives. Evaporative losses from the reservoir were not estimated for the closed loop PHES and water replenishment for this technology is assumed to be from a nearby water resource and at minimal cost.

2.4. Conceptual Cost Estimates and Forecasts

This study considers typical utility-grade design considerations, contracting, and execution methods for the various technologies under consideration. The parameters developed as part of this effort do not consider significant conceptual design but are considered to be representative of as-built projects in today's marketplace. The conceptual project costs developed for this evaluation consider an engineer, procure, construct (EPC) project delivery for "inside-the-fence" project scope and associated costs, an estimate for major utility interconnections, and an estimate of typical owner's costs. Conceptual-level project capital costs were developed for each technology based on the following:

- Overnight, turnkey EPC delivery in 2018 dollars (escalation excluded)
- EPC contractor direct equipment and labor costs, construction and project indirect costs, and other fees and contingencies typical for EPC project delivery
- Project location on a site/land generally suitable for development
- Natural gas compressor included for combustion turbine resource options
- Municipal and other interconnections assumed at the site fence/boundary
- Conceptual costs for electric transmission interconnection, natural gas lateral and gate station, and utility related "outside-the-fence" scope has been estimated and identified for each technology option. Note that these costs do not account for any electrical and gas system network upgrades.
- An opinion of probable owner's cost is identified separately for each technology, and typically includes costs associated with project development, permitting, contracting, owner's engineering support, etc.[9]
- A cost allocation for AFUDC for each resource was developed by PSE and is included in the cost estimate.
- American Association of Cost Engineering International (AACE) Class 5 level of accuracy (L: -20% to -50%; H: +30% to +100%) suitable for comparative purposes
- Capital costs expressed in $/kW are based on the full load, winter peak day net electric output for thermal and biomass technologies

Conceptual capital cost estimates are broken down into the following major cost categories for each technology considered:

- Major equipment costs
- Balance-of-plant (BOP) costs
- Construction and project indirect costs
- Owner's costs

[9] The opinion of probable owner's costs does not include allowance for funds used during construction (AFUDC)/interest during construction (IDC). AFUDC was estimated separately by PSE.

Additionally, estimated owner's costs are broken down into the following major categories for each technology:

- Project development and management
- Execution support – engineering and construction
- Owner's contingency
- Miscellaneous – initial spares, service agreements, financing, and other

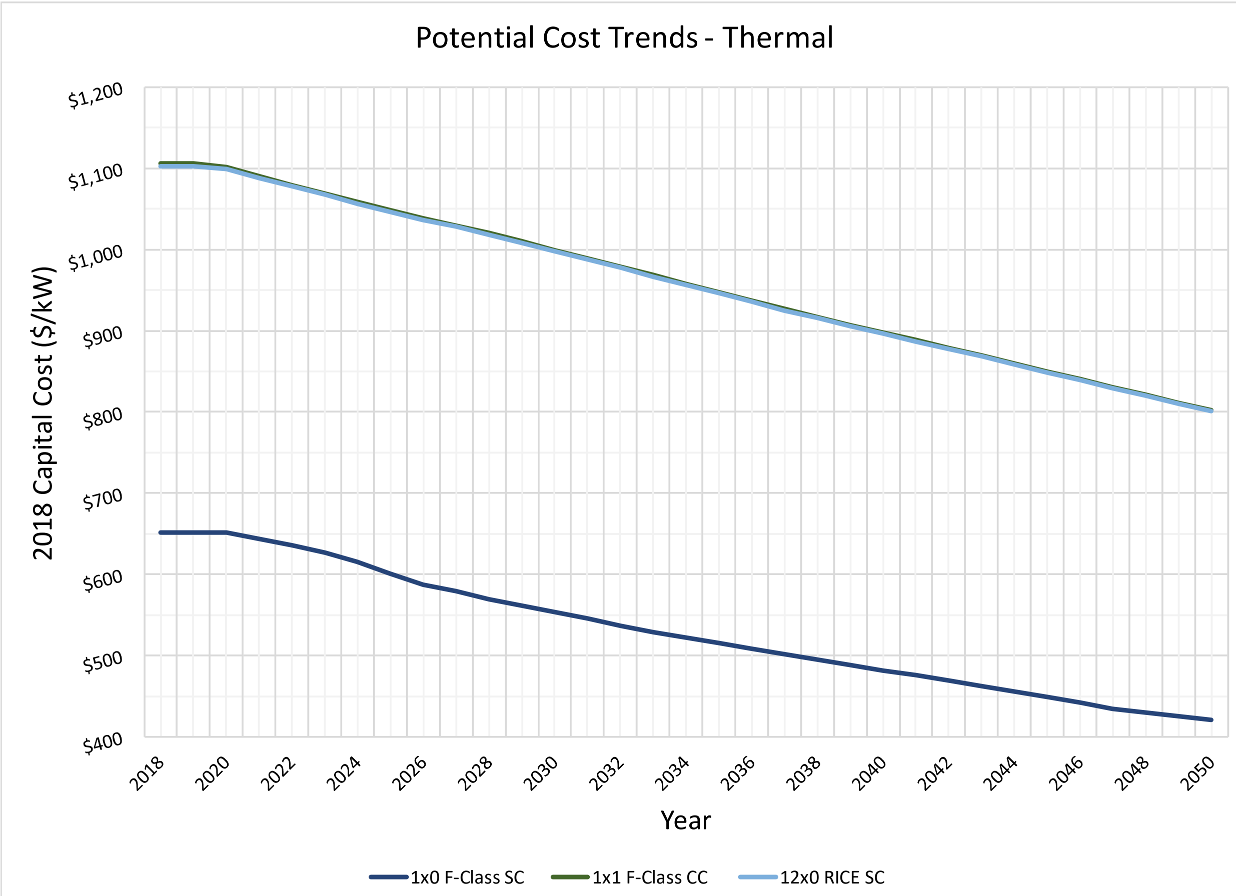
All conceptual cost estimates developed for this effort consider the current power generation marketplace, feedback from equipment suppliers and contractors, publicly available information, and costs observed from previous project developments.

Costs presented herein are based on current day cost expectations, results of actual projects, and equipment budgetary quotations, where available. They are intended to reflect the current status of the industry with respect to recent materials and labor escalation. The estimates developed for this assessment are conceptual in nature, are for comparative and resource planning purposes only, and are not to be used for budget planning purposes. Any opinions of probable project cost or probable construction cost provided by HDR are made on the basis of information available to HDR and previous project experience. Since HDR has no control over the cost of labor, materials, equipment or services furnished by others, contractor's means and methods, or future market conditions, HDR does not warrant that proposals, bids, or actual project or construction costs will not vary from the costs provided herein.

2.4.1. Cost Trends

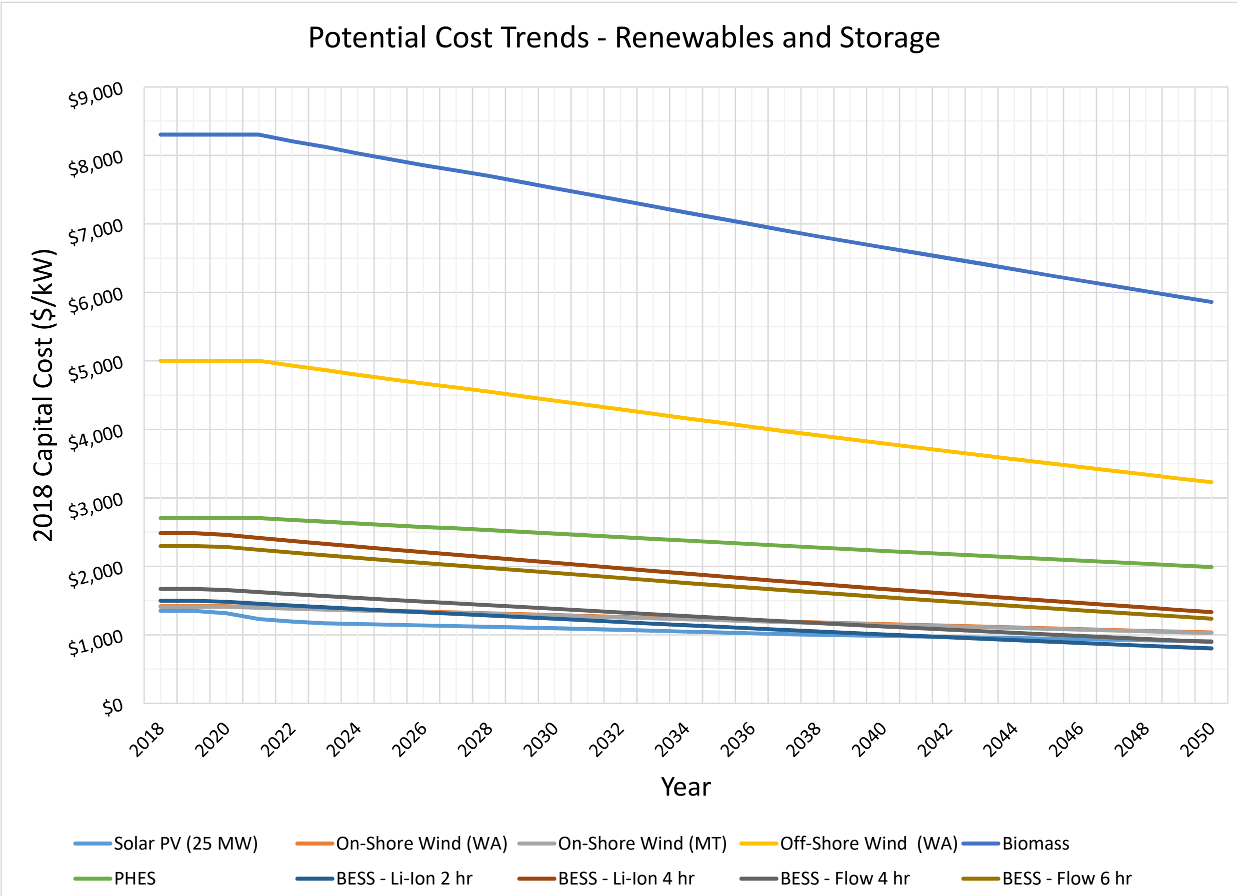
It is anticipated that with increasing experience in the marketplace through widespread application of a certain power generation technology, the initial capital costs would decrease as design, fabrication, and installation of that technology becomes more mature and is well understood. To understand the impact of technology maturity, and potential capital cost trends over time, potential cost trend curves 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 cost trends. All costs are referenced in 2018 US dollars and are forecasted from 2018 to 2050. In instances where the NEMS forecasted cost projections did not start until 2020 or 2021, costs were estimated to be unchanged from 2018 until the start of the NEMS forecast. The figures below summarize potential cost trends for the generation and storage technologies considered in this evaluation.

Figure 2.4-1. Potential Cost Trends – Thermal Technologies[10]



[10] The curves for the 1x1 F-Class CC and 12x0 RICE SC configurations appear to be the same based on similar overnight capital costs on a $/kW basis.

Figure 2.4-2. Potential Cost Trends – Renewable and Storage Technologies[11]



[11] Cost trends are shown for the 100 MW on-shore wind and 25 MW solar configurations. Costs associated with the larger configurations (300 MW on-shore wind and 100 MW solar) would trend similarly.

2.5. Project Schedules and Cash Flow Basis

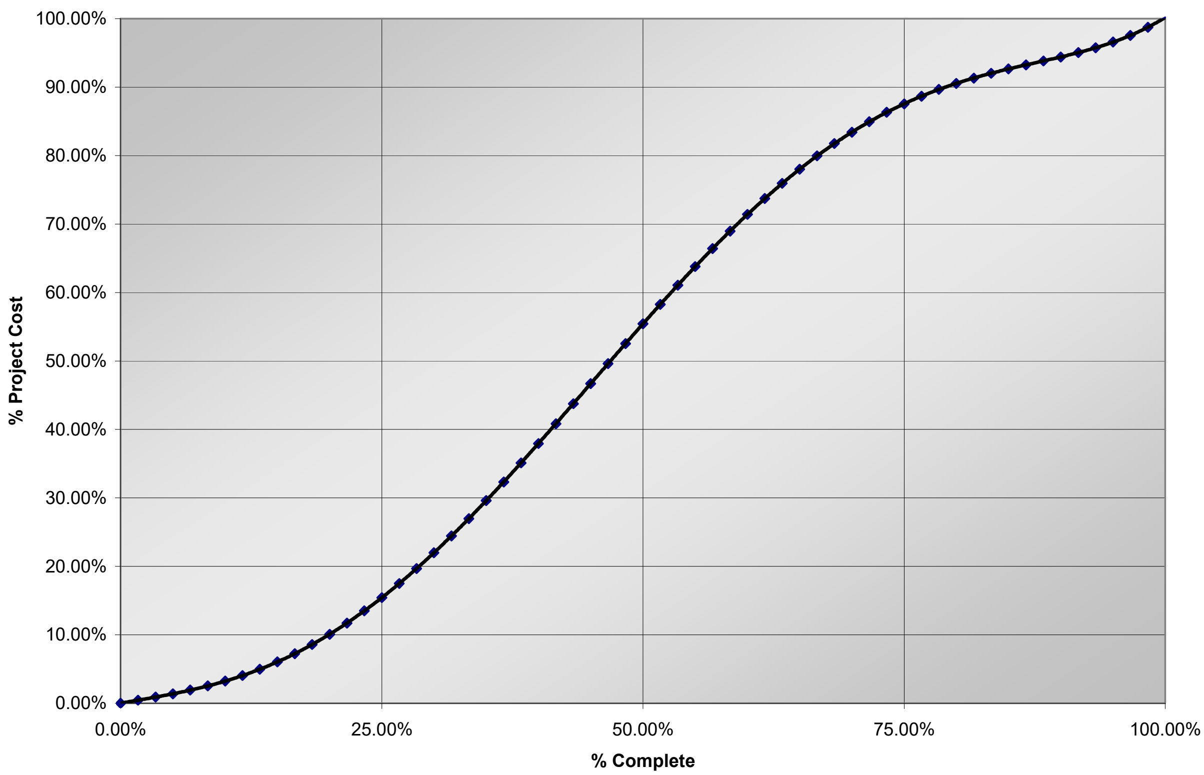
A conceptual, site- and project-generic project implementation schedule was developed for each technology from contractor notice to proceed (NTP) through project commercial operation date (COD). These schedules do not consider project development activities ahead of contractor NTP such as feasibility and conceptual design, permitting, contracting, and regulatory activities.

These implementation schedules were developed based upon a review of key project milestones, construction activities, primary equipment lead times provided by OEMs, and experience on previous/similar applications. These schedules are considered conceptual in nature but represent a reasonable indication of timing of key activities throughout the execution of the project.

Conceptual project implementation schedules are included as Appendix A. Given significant site- and development-specific uncertainties associated with implementation durations for PHES, an implementation schedule for this technology is not presented herein. However, an expected duration range is discussed.

For monthly cash flow determinations during execution, 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 the figure below. Representative EPC cash flow curves from NTP to COD are included for each technology in Appendix B.

Figure 2.5-1. Representative Cash Flow Curve



2.6. Conceptual O&M Cost Estimates

Conceptual O&M costs were developed for each technology, considering fixed O&M costs and variable O&M costs, as applicable.

Fixed O&M costs are expenses required to operate and maintain a generation facility that are generally not dependent on electrical production/operation of the facility. Fixed O&M costs generally are inclusive of costs associated with staffing, fixed/recurring equipment O&M, spare parts inventory, building maintenance, and others. Staffing cost assumptions are summarized below.

Table 2.6-1. Staffing Cost Assumptions[12]

Staff Costs		First Year Cost
Annual Cost for Salaried Staff (Fully-Burdened)	$/year	$180,000
Annual Cost for Hourly staff (Fully-Burdened)	$/year	$180,000

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 full load net plant output at winter day ambient conditions. Fixed O&M costs presented herein do not include costs associated with insurances, property taxes, or corporate general and administrative (G&A) costs.

Variable O&M costs are those expenses that are dependent on electrical production/operation of a facility. Variable O&M costs presented herein are non-fuel variable O&M costs. Non-fuel variable O&M costs include costs associated with consumption and disposal of materials associated with operation, including water and wastewater, as well as variable costs associated with operating facility equipment, as applicable. Consumables unit cost assumptions are summarized below.

Table 2.6-2. Consumables Unit Cost Assumptions

Consumables Unit Costs		
Annual Escalation Rate	%	2.5%
Ammonia (as 19% NH3)	$/ton	$166.52
Urea	$/gal	$2.13
Makeup Water	$/k-gal	$1.50
Demineralized Water	$/k-gal	$3.50
Cycle Chemical Feed (per Ton of Steam)	$/ton	$0.02
Wastewater Treatment	$/k-gal	$1.00
Engine Lube Oil	$/gal	$7.00

[12] First year staffing costs provided by PSE.

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) costs.

2.7. Dispatch Modeling Inputs

Inputs for dispatch modeling were developed and summarized for PSE use in their modeling software. Dispatch modeling inputs include the performance attributes and O&M costs previously discussed as well as additional operating attributes associated with each technology including startup/shutdown durations, ramp rates, turn down capability, charging considerations, and others. The following resource capacity factors were provided by PSE and used in the study to estimate annual O&M costs. The actual capacity factors/utilization for the resources listed in the table would depend on dispatch modeling. Capacity factors/utilizations of other resource types was estimated based on anticipated production (renewables) or based on storage capability/cycles (PHES and BESS).

Table 2.7-1. Technology Specific Annual Capacity Factor

Resource		Annual Capacity Factor	Annual Starts
1x0 F-Class CT	%	4%	75
1x1 F-Class CC	%	85%	200
12x0 18 MW RICE	%	15%	300
Biomass	%	85%	50

Parameters are provided for each technology option in Appendix C.

3. Thermal Generation Resource Options

3.1. Technology Overview

Thermal generation options considered in this evaluation include combustion turbine (CT) and reciprocating internal combustion engine (RICE) technologies in either simple cycle or combined cycle configuration. Both are commonly implemented technologies for utility scale power generation applications using pipeline natural gas as the primary fuel source.

Simple cycle CT plants are generally used to supply power during periods of peak electric demand (peaking power) due to their low capital cost, short construction schedule, rapid response (e.g. quick start capability), and ability to operate cost effectively at low capacity factors compared to other power generation alternatives.

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.

A combined cycle facility involves the addition of a heat recovery steam generator (HRSG) to the exhaust of a CT or RICE unit for the conversion of exhaust heat into steam that drives a steam turbine generator. The result is a significant increase in thermal efficiency over that of a simple cycle configuration. As compared to simple cycle technologies, the attributes of a combined cycle configuration include higher thermal efficiencies and less responsiveness in terms of starting and ramping, which make this technology more suitable for base load or intermediate dispatch applications. Combined cycle applications utilizing RICE are much less common as compared to applications utilizing CTs given the relatively low exhaust energy available from RICE technology and, as such, a RICE combined cycle configuration is not considered in this evaluation.

The simple cycle CT and RICE options considered in this analysis include the option to switch to a backup fuel in the event that the natural gas supply to the power generation facility is curtailed. A natural gas-only RICE configuration is also considered. The combined cycle configuration considers natural gas fuel only.

The following subsections provide a description of the various thermal generation resource options considered for this evaluation.

3.1.1. Simple Cycle 1x0 CT – F-Class Frame Technology (Gas, Diesel)[13]

This option involves a nominal 250 MW (237 MW winter peak) frame-type gas turbine operating in a simple cycle configuration and considering natural gas[14] and diesel fuel oil dual fuel capability. For this technology, an inlet air evaporative cooler is included and a selective catalytic reduction (SCR) system and oxidation catalyst are included for air emissions control.

3.1.2. Combined Cycle 1x1 CT – F-Class Frame CT with Supplemental Firing[15]

The nominal 350 MW (348 MW winter peak) 1x1 combined cycle configuration consists of a single F-class frame CT paired with a triple pressure reheat HRSG. The HRSG generates steam using the hot exhaust gas from the CT. This steam is fed to a steam turbine generator to generate additional electrical output. The assumed configuration for this option uses a wet mechanical draft cooling tower for thermal cycle heat rejection. The CT was also assumed to be equipped with an inlet air evaporative cooler and SCR system/oxidation catalyst for emissions control in the HRSG. This configuration considers HRSG supplemental duct firing for additional electric production from the steam turbine resulting in a net output rating of nominally 362 MW (winter peak).

3.1.3. Simple Cycle 12x0 RICE – 18 MW Class (Gas Only)

This option considers a configuration consisting of 12 nominally 18 MW RICE burning natural gas as the only fuel. The engines are assumed to have an SCR system/oxidation catalysts for emissions reduction and engine cooling is achieved with fin-fan radiators.

3.1.4. Simple Cycle 12x0 RICE – 18 MW Class (Gas, Diesel)

This option considers a plant consisting of 12 nominally 18 MW RICE burning natural gas as the primary fuel and diesel as the secondary fuel. The engines are assumed to have an SCR system/oxidation catalysts for emissions reduction and engine cooling is achieved with fin-fan radiators. Because of the inherent differences in the dual fuel machines relative to the single fuel engines, the dual fuel engines have a lower output and efficiency compared to the gas-only models even when operating on natural gas. While the gas-only engines use spark ignition, the dual fuel (NG/diesel) configuration uses compression ignition. As a result, the dual fuel configuration requires a liquid oil pilot system, which leads to a decrease in output and efficiency for the dual fuel machines.

3.2. Commercial Status

CTs and RICE in simple or combined cycle configuration are well proven and commercially available technologies for power generation. The major CT and RICE OEMs have significant experience throughout the world. RICE units generally range in size from 100 kW to 20 MW and current CT offerings range in size from 1.5 MW to 370 MW. A list of some of the most prevalent

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[13] "1x0" refers to a configuration with a single prime mover (CT/RICE) and no heat recovery/steam turbine.

[14] This analysis assumes that natural gas fuel compression is required for the CT options and not required for the RICE options.

[15] "1x1" refers to a configuration with a single prime mover (CT/RICE) and the addition of and HRSG/steam turbine.

suppliers for CT and RICE technologies is provided in Table 3.2-1. Numerous HRSG and steam turbine suppliers exist for combined cycle applications, also.

Table 3.2-1. CT and RICE Manufacturers

Turbine OEMs	RICE OEMs
General Electric	Caterpillar
Hitachi (Mitsubishi)	Cummins
Kawasaki	Fairbanks Morse
Mitsubishi	GE Jenbacher
PW Power Systems (Mitsubishi)	GE Waukesha
Rolls-Royce (Siemens)	Kawasaki
Siemens	MAN Turbo & Diesel
Solar Turbines	Mitsubishi
	Wartsila

3.3. Operational Considerations

3.3.1. Fuel Assumptions

For the thermal generation assets described in this report, natural gas was assumed to be the primary fuel source with some options also considering fuel oil as a secondary fuel. The assumed natural gas and diesel fuel oil higher heating values (HHV)[16] are provided in Table 3.3-1. A natural gas fuel compressor was assumed for the thermal generation resource options that use combustion turbines.

Table 3.3-1. Assumed Fuel Characteristics

Fuel Analysis		Natural Gas	Fuel Oil
HHV	btu/lb	22,029	18,200
HHV/LHV	-	1.108	1.070

3.3.2. Plant Performance

Overall new and clean net plant output and heat rate are summarized for each of the thermal technologies in Tables 3.3-2 and Tables 3.3-3. Output and thermal degradation over the asset life for the thermal options will occur, with such estimated based on supplier degradation curves and typical equipment degradation.

[16] Thermal heat rates are presented on an HHV basis in this report, which considers the latent heat of vaporization of the water in the combustion products, versus lower heating value (LHV) basis, which does not.

Table 3.3-2. Estimated Summer Performance

Summer Peformance	Summer Peak 100%		Summer Average 100%	
	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)
	kW	Btu/kWh	kW	Btu/kWh
1x0 F-Class CT (NG)	218,692	9,991	219,982	9,950
1x0 F-Class CT (FO)	211,086	10,132	212,267	10,090
1x1 F-Class CC (Fired)	348,157	6,728	349,407	6,714
1x1 F-Class CC (Unfired)	329,486	6,638	330,936	6,618
12x0 18 MW RICE SC (NG Only)	218,988	8,464	218,988	8,436
12x0 18 MW Dual Fuel RICE (NG)	201,469	8,601	201,469	8,573
12x0 18 MW Dual Fuel RICE (FO)	173,460	8,800	173,460	8,771

Table 3.3-3. Estimated Winter Performance

Winter Performance	Winter Average 100%		Winter Peak 100%	
	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)
	kW	Btu/kWh	kW	Btu/kWh
1x0 F-Class CT (NG)	229,808	9,846	236,941	9,774
1x0 F-Class CT (FO)	221,879	9,978	228,865	9,900
1x1 F-Class CC (Fired)	359,106	6,747	366,725	6,761
1x1 F-Class CC (Unfired)	340,303	6,648	348,165	6,649
12x0 18 MW RICE SC (NG Only)	218,988	8,435	218,988	8,428
12x0 18 MW Dual Fuel RICE (NG)	201,469	8,571	201,469	8,565
12x0 18 MW Dual Fuel RICE (FO)	173,460	8,769	173,460	8,763

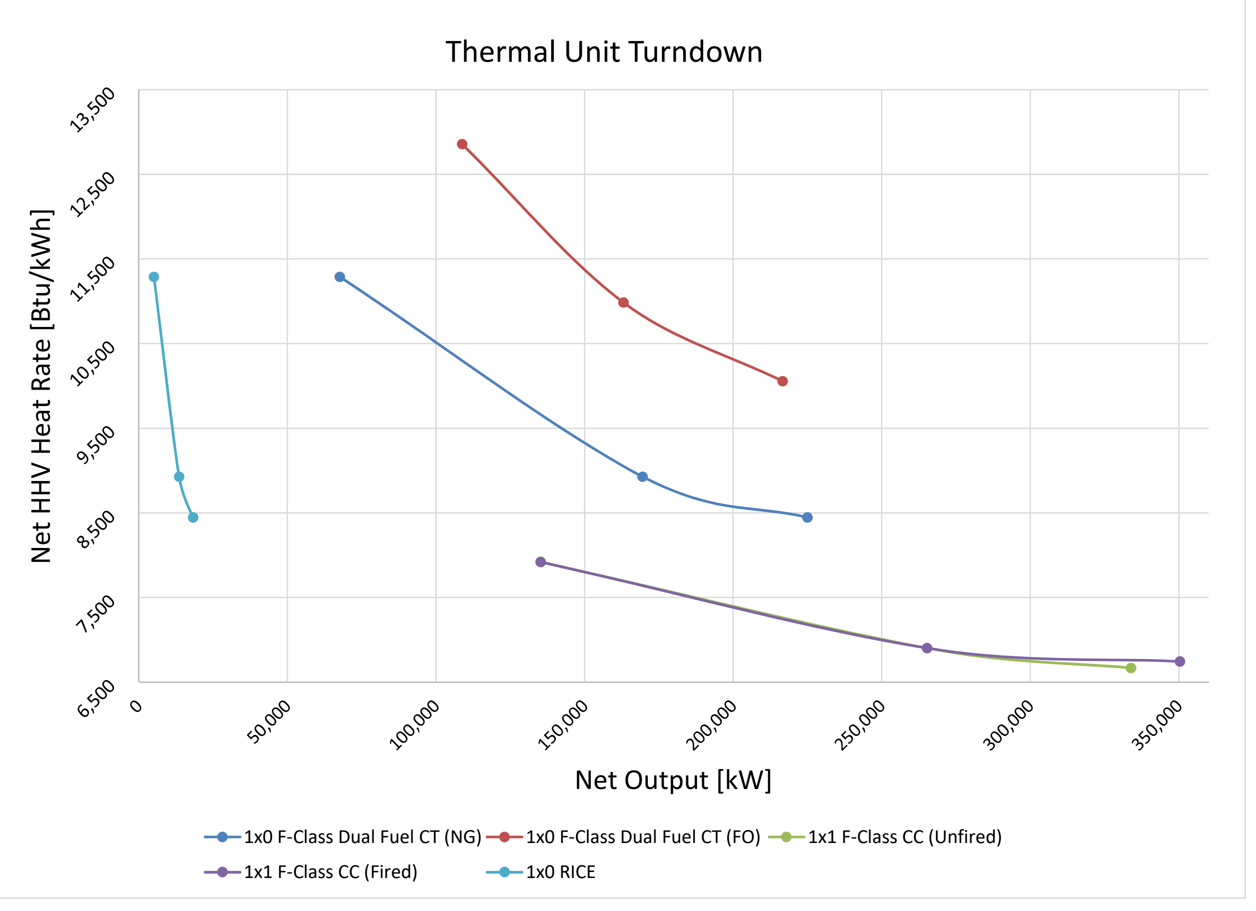
Plant performance has also been developed at part load operating conditions from 100% load to minimum emission compliance load (MECL) for each of the thermal options based on new and clean average life of plant performance at ISO conditions[17]. Note that CC duct burners are typically not utilized for when CT loads are less than 100%. Table 3.3-4 summarizes unit turn down capability and performance in tabular form and the same data is presented graphically in Figure 3.3-1. The RICE turn down performance is depicted for a single unit in operation.

[17] ISO conditions are 59 degrees F, 60% relative humidity, and 0 ft. above mean sea level (AMSL).

Table 3.3-4. Estimated Thermal Unit Performance at ISO Conditions

ISO Performance	ISO 100%		ISO 75%		ISO MECL	
	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)
	kW	Btu/kWh	kW	Btu/kWh	kW	Btu/kWh
1x0 F-Class CT (NG)	224,814	9,904	169,351	10,793	67,549	15,794
1x0 F-Class CT (FO)	216,651	10,056	163,069	10,985	108,788	12,856
1x1 F-Class CC (Fired)	355,278	6,724	266,908	6,859	134,003	7,988
1x1 F-Class CC (Unfired)	336,095	6,624	266,908	6,859	134,003	7,988
12x0 18 MW RICE SC (NG Only)	18,249	8,445	13,547	8,927	5,084	11,288
12x0 18 MW Dual Fuel RICE (NG)	16,789	8,582	12,463	9,072	4,677	11,471
12x0 18 MW Dual Fuel RICE (FO)	14,455	8,780	10,731	9,282	4,027	11,736

Figure 3.3-1. Estimated Thermal Unit Performance at ISO Conditions



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 3.3-5 below. The following assumptions and clarifications pertain to this table:

- 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 CT 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 option.
- Minimum run times are representative of a typical 30 minute startup to full load and plant emission compliance. 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 CT options if started in under 1 hour.

Table 3.3-5. Plant Miscellaneous Operating Characteristics

Configuration		1x0 F-Class SC	1x1 F-Class CC	12x0 RICE (1 Unit)	Biomass
Ramp Rate	MW /min	40	40	16	2
Minimum run time	min	60	60	35	240
Minimum down time	min	15	15	15	60
Start-up time to full load at warm start	min	21	60	5	240
Start-up time to full load at cold start	min	21	150	5	360

3.3.3. Staffing Requirements

Typical staffing levels for a simple cycle configuration are minimal and, for the purposes of this analysis, include one salaried and two hourly staff. For a combined cycle configuration, staffing levels are typically greater as compared to a simple cycle configuration: six salaried and 18 hourly staff were assumed for the combined cycle configurations.

3.3.4. Environmental Considerations

AIR EMISSIONS

Plant emission rates and air quality control equipment assumed for each natural gas generation option are those typically expected to be achievable and permittable based on the fuels used and the specific generation technology. Emissions rates were estimated and are provided on a lb/mmBtu basis.

Air emissions estimates for the various options are presented in Tables 3.3-6 for the natural gas only and dual fuel configurations.

Table 3.3-6. Estimated Air Emission Rates

Estimated Emissions	Heat Input	Net Output	NOx	PM	SO2	CO	VOC	CO2
	mmbtu/hr	MW	lb/mmbtu	lb/mmbtu	lb/mmbtu	lb/mmbtu	lb/mmbtu	lb/mmbtu
1x0 F-Class CT (NG)	2,316	237	0.0039	0.0057	0.0014	0.0049	0.0014	118
1x0 F-Class CT (FO)	2,266	229	0.0136	0.0057	0.0082	0.0148	0.0042	160
1x1 F-Class CC (Fired)	2,480	367	0.0081	0.0057	0.0014	0.0049	0.0014	118
1x1 F-Class CC (Unfired)	2,315	348	0.0081	0.0057	0.0014	0.0049	0.0014	118
12x0 18 MW RICE SC (NG Only)	1,846	219	0.0292	0.0057	0.0014	0.0370	0.0351	118
12x0 18 MW Dual Fuel RICE (NG)	1,726	201	0.0373	0.0057	0.0019	0.0370	0.0057	122
12x0 18 MW Dual Fuel RICE (FO)	1,520	173	0.1297	0.0057	0.0082	0.0493	0.0082	160

__Note__: Filterable and condensable PM indicated in table. For natural gas-fired equipment, a typical assumption is that PM2.5 = PM10 = PM. All the PM is assumed to be in the smallest (PM2.5) size range.

WATER SUPPLY/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. The rates also assume the utilization of inlet air evaporative cooling on peak summer day conditions for the CT alternatives. For applicable systems, a wet, mechanical draft heat rejection system has been utilized. Table 3.3-7 summarizes the estimated water consumption and wastewater discharge for each technology option. These rates are based upon the assumption that the facility design incorporates recycling and reusing water to the greatest extent possible.

Table 3.3-7. Estimated Water Consumption/Wastewater Discharge

Estimated Water Consumption / Wastewater Discharge (Summer)	Summer Peak		Summer Average	
	Water Consumption	Wastewater Discharge	Water Consumption	Wastewater Discharge
	gal/MWH	gal/MWH	gal/MWH	gal/MWH
1x0 F-Class Dual Fuel CT (NG)	12.7	2.6	0.1	0.1
1x0 F-Class Dual Fuel CT (FO)	13.1	2.7	0.1	0.1
1x1 F-Class CC (Fired)	316.3	63.4	257.3	51.6
1x1 F-Class CC (Unfired)	309.0	62.0	248.8	49.9
12x0 18 MW RICE SC (NG Only)	0.8	0.8	0.8	0.8
12x0 18 MW Dual Fuel RICE (NG)	0.9	1.1	0.9	1.1
12x0 18 MW Dual Fuel RICE (FO)	1.0	1.0	1.0	1.0

3.3.5. Combined Cycle Dry Cooling Impacts

The combined cycle option considered in this evaluation assumes the use of wet, mechanical draft cooling via a conventional wet condenser and a forced draft cooling tower. An option exists to accomplish the same heat rejection via air cooling using an air cooled condenser. As a general rule, the use of an air cooled condenser has the effect of decreasing plant net output, increasing plant net heat rate, and drastically decreasing the total water consumption of the plant. For combined cycle configurations, associated performance impacts are typically in the range of:

- Nominally 3% decrease in output
- Nominally 3% increase in heat rate

For a wet cooled combined cycle plant, the majority of the water consumption is due to cooling tower makeup water flow. For this reason, a plant that employs air cooling would be expected to reduce its overall water consumption by 97% or more as compared to an equivalent wet cooled facility.

3.4. Conceptual Capital Cost Estimates

Table 3.4-1 summarizes the conceptual capital cost estimates for overnight turnkey EPC delivery in 2018 dollars. Costs are presented on a $/kW basis by dividing the conceptual capital costs by the net winter peak output. The cost estimating basis is summarized in Section 2.5.

Table 3.4-1. Conceptual Capital Costs

Conceptual Capital Costs	Winter Peak Net Output	Major Equipment	BOP	Indirects	Subtotal - EPC	Owner's	AFUDC costs	Total Project Cost	Electric - Outside the Fence	Nat Gas - Outside the Fence	Total - Outside the Fence	Total with Interconnect
	MW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
1x0 F-Class CT (Dual Fuel)	237	$191	$190	$173	$554	$92	$39	$686	$83	$56	$139	$825
1x1 F-Class CC (Single Fuel)	348	$289	$330	$279	$898	$142	$90	$1,131	$60	$38	$99	$1,229
12x0 18 MW RICE (Single Fuel)	219	$449	$162	$231	$842	$134	$67	$1,043	$87	$61	$148	$1,192
12x0 18 MW RICE (Dual Fuel)	201	$512	$191	$262	$965	$153	$77	$1,196	$95	$67	$162	$1,357

AFUDC costs were estimated by PSE as a percentage of project EPC costs at 7% for simple cycle, 10% for combined cycle, and 8% for RICE configurations. AFUDC costs are included in the table above. The opinion of probable owner's costs represented above can roughly be broken down into the following general cost categories.

Table 3.4-2. General Owner's Costs Categories[18]

Opinion of Probable Owner's Costs		Thermal
Project Development/Management	%	2%
Execution Support	%	1%
Owner's Contingency	%	8%
Miscellaneous	%	5%
Total	%	16%

The following tables below provide assumptions and information related to outside the fence electrical and natural gas infrastructure.

[18] Percentages refer to the owner's costs as a percentage of EPC project costs.

Table 3.4-3. Electrical Infrastructure Costs Outside the Fence

Plant Configuration	Winter Peak Net Output (MW)	Radial Line /POI infrastructure	Cost ($ MM)			Cost ($/kW)
			Radial Line	POI infrastructure	Total	
1x0 F-Class Simple Cycle	237	230 kV 5 mile radial line to POI. Breaker and one half interconnection arrangement at POI	$9.8	$9.9	$19.6	$82.8
1x1 F-Class Combined Cycle	348	230 kV 5 mile radial line to POI. Breaker and one half interconnection arrangement at POI	$9.8	$11.2	$20.9	$60.1
12x0 Simple Cycle	219	230 kV 5 mile radial line to POI. Breaker and one half interconnection arrangement at POI	$9.8	$9.4	$19.1	$87.3

Table 3.4-4. Natural Gas Infrastructure Costs Outside the Fence

Plant Configuration	Winter Peak Net Output (MW)	Gas Lateral /Connection	Cost ($ MM)			Cost ($/kW)
			Lateral Line	Gate Station	Total	
1x0 F-Class Simple Cycle	237	12in 400psi 5 mile lateral line from plant boundary to new fuel gate station. New fuel gas gate station with metering.	$12.1	$1.3	$13.4	$56.5
1x1 F-Class Combined Cycle	348					$38.5
12x0 Simple Cycle	219					$61.1

3.5. Conceptual O&M Costs

Estimated O&M costs for the thermal generation options are summarized in Table 3.5-1. Estimated O&M costs include fixed and variable O&M costs associated with operating and maintaining the facility and consider costs associated with long term service agreements for major equipment.

The simple cycle CT configuration assumes a peaking dispatch profile with a nominal 4% annual capacity factor (350 hours of operation annually). The simple cycle RICE configuration assumes a peaking dispatch profile of 15% (1,314 hours of operation annually). The combined cycle configuration assumes a base load dispatch profile with a nominal 85% capacity factor (7,446 hours of operation annually).

Table 3.5-1. Conceptual O&M Costs[19]

Conceptual O&M Costs	Fixed O&M	Variable O&M		
		Major Maintenance Adder	Consumables and BOP	Total Variable O&M
	$/kW-yr	$/MWh	$/MWh	$/MWH
1x0 F-Class CT (NG)	$3.93	$5.87	$0.69	$6.56
1x0 F-Class CT (FO)	$4.09	$6.09	$0.87	$6.96
1x1 F-Class CC (Fired)	$13.44	$0.48	$1.97	$2.45
1x1 F-Class CC (Unfired)	$14.16	$0.50	$2.02	$2.52
12x0 18 MW RICE SC (NG Only)	$3.74	$4.22	$1.08	$5.30
12x0 18 MW Dual Fuel RICE (NG)	$4.12	$4.59	$1.21	$5.80

[19] For the dual fuel configuration, O&M costs indicated are based on limited backup (FO) firing.

As indicated, variable O&M buildup includes a major maintenance adder for the CTs (typically expressed on a $/start basis as clarified in Table 3.5-2 below) as well as consumables and BOP. Variable O&M cost for the simple cycle CT configuration in the table above is based on 75 starts per year and 4% annual capacity factor. See Table 2.7-1 for assumptions related to starts and annual capacity factor for the different resource options.

Table 3.5-2 provides a breakdown of the startup costs and includes major maintenance adder as well as cost of consumables.

Table 3.5-2. Buildup of Start Up costs

Start Up Costs	Major Maintenance Adder	Consumables	Total Start Up Cost
	$/Start	$/Start	$/Start
1x0 F-Class CT (NG)	$6,500	$2	$6,502
1x0 F-Class CT (FO)	$6,500	$9	$6,509
1x1 F-Class CC (Fired)	$6,500	$66	$6,566

3.6. Project Implementation Schedule

Estimated project implementation schedules were developed for each of the thermal generation options based on current day contracting approaches and methodologies and are included in Appendix A. Representative capital spend curves were also developed and are included in Appendix B. From contractor NTP to COD, the durations for the simple cycle CT configuration, the 12 unit simple cycle RICE configuration, and the combined cycle configuration are anticipated to be in the range of 20 to 22 months, 26 to 28 months, and 30 to 32 months, respectively.

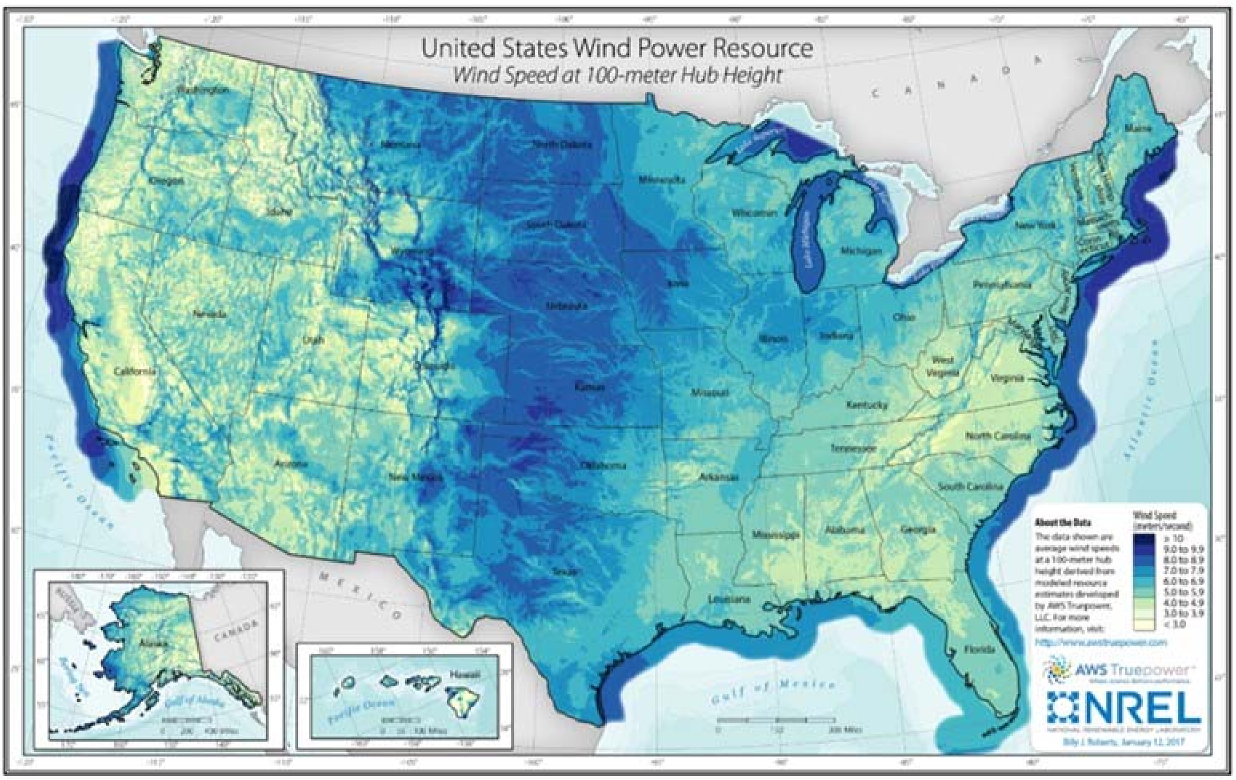
4. On-Shore Wind Technology

For the purpose of this study, nominal 100 MW and 300 MW wind farms were evaluated as a representative, proxy project sizes at sites in Washington and Montana.

4.1. Technology Overview

Wind power is generated by converting the kinetic energy of wind into electricity by rotating turbine blades that are connected electrical generator. Higher wind speeds (better wind resource) result in more efficient facilities and higher annual capacity factors. A map of wind speeds in the U.S. is shown below in Figure 4.1-1.

Figure 4.1-1. U.S. Wind Speeds at 100m Hub Height



A wind turbine ideally would be located where wind flow is non-turbulent and constant year round without excessive or extreme gusts. Wind speed typically increases with altitude and is higher over open areas without windbreaks such as trees or buildings. Wind data is typically collected for a year or more via meteorological towers to determine general viability of site.

Adequate spacing between the wind turbines must be maintained to reduce wind energy loss from interferences from nearby turbines. To minimize efficiency losses, wind turbines are commonly spaced three to five rotor diameters apart along an axis that is perpendicular to the prevailing wind direction and five to ten rotor diameters apart along an axis that is parallel to the prevailing wind direction.

4.2. Commercial Status and Current Market

Wind power technology has been adapted and implemented globally. Advances in wind turbine designs have helped to improve achievable plant efficiencies compared to previous designs, allowing wind turbines to be economically implemented in lower wind power class regions.

4.2.1. Current Market Influences

The Federal Production Tax Credit (PTC) has been instrumental in supporting the deployment and growth of wind energy in the U.S.[20] The PTC currently offers a $0.014/kWh tax credit over a 10-year time period for wind facilities commencing construction in 2018 for the electricity generated from wind. As this tax credit is being phased down, this value represents a 40% reduction from the $0.024/kWh base credit originally available under this program. For wind facilities commencing construction in 2019, the tax credit amount is reduced by 60% from the base credit. For projects commencing construction after 2019, the tax credit is no longer applicable. The phase out of the PTC is summarized below.

Table 4.2-1. Federal PTC Phase Out Summary for Wind[21,22]

Federal PTC Phase Out					
Year Construction Begins	2016	2017	2018	2019	Future
Wind PTC ($/kWh)	$0.024	$0.019	$0.014	$0.010	-

4.3. Operational Considerations

Wind farms are typically designed for a 20 year life, but turbine suppliers have suggested that well maintained turbines could last up to 25 years depending on the service conditions at the site. Typical wind turbine sizes range from nominally 1.5 MW to 5 MW.

Wind turbine capacity is based largely on the length of the propeller blades. Taller turbines are able to use longer blades for higher output capacity, but are also able to take advantage of the better wind speeds available at greater heights (while also considering related aviation regulations and requirements).

Due to the maturity and relatively long operating history of wind power technologies, there are limited technical performance risks or unknown factors involved in utilizing this technology. Ongoing gearbox and generator design improvements have enhanced the reliability of the equipment.

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[20] Large wind applications are also eligible for the Federal Investment Tax Credit (ITC) if placed into service prior to the end of 2019. However, most utility-scale wind applications pursue the Federal PTC in lieu of the Federal ITC based on benefits realized.

[21] https://www.energy.gov/savings/renewable-electricity-production-tax-credit-ptc

[22] The exact value of the Federal PTC in a given year depends on the inflation adjustment factor used by the Internal Revenue Service (IRS).

4.3.1. Performance Data

For this evaluation, proxy wind farm locations were selected in central and eastern Montana and southeastern Washington as shown in Figures 4.3-1 and 4.3-2. Two sites in Central Montana were chosen, one in close proximity to the Colstrip transmission line (Site #1) and a second site near Great Falls (Site #2), which was also assumed to connect to the Colstrip transmission line. Additionally, a third site was evaluated in eastern Montana and is assumed to be connected to the local transmission system (Site #3).

Figure 4.3-1. Proxy Wind Farm Sites in Montana

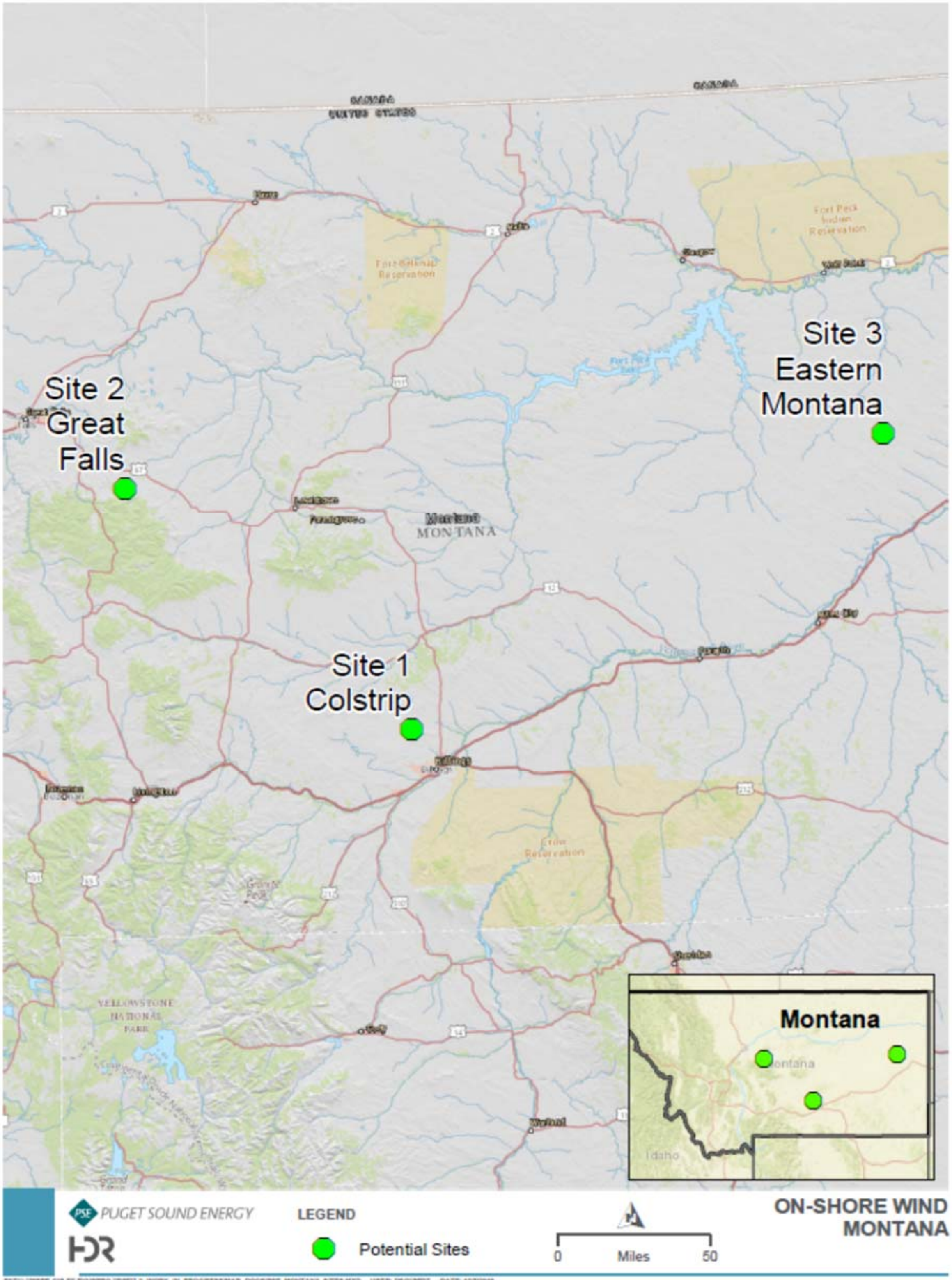

Figure 4.3-2. Proxy Wind Farm Site in Southeastern Washington

An average net capacity factor (NCF) range for a wind power facility is typically in the range of 25 to 50 percent depending on available wind energy within the region. The NCFs for this evaluation were estimated from publicly available wind resource data and include all losses up to the project busbar (i.e. transmission losses are not included). The estimated capacity factors for each of the representative sites are summarized below in Table 4.3-1[23].

Table 4.3-1. Wind Turbine Site Estimated NCFs

Estimated Wind Annual Average NCF		
Central Montana (Site #1)	%	35.5%
Central Montana (Site #2)	%	42.4%
Eastern Montana (Site #3)	%	45.8%
Southeastern Washington (Site #4)	%	31.9%

Wind resource data was utilized from the NREL WIND Toolkit application. The WIND Toolkit application includes meteorological conditions and turbine power for over 120,000 sites in the United States. The WIND Toolkit application was created through collaborative efforts between NREL and 3TIER by Vaisala.

4.3.2. Plant Staffing

Staffing for a wind power plant generally assumes the utilization of a remote monitoring/operating system. Typical staffing requirements are minimal and for the purpose of this analysis, include one salaried and two hourly staff.

4.4. Conceptual Capital Cost Estimate

Table 4.4-1 summarizes the estimated total project costs for each of the wind sites considered[24]. The conceptual project capital costs are based on overnight turnkey EPC delivery in 2018 dollars where the EPC contractor procures the major equipment, including the wind turbines.

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[23] Montana Site #3 represents a benchmark case with potentially better wind resource as compared to the other sites evaluated in Montana. However, it is important to note that the NCF for this site is more aggressively estimated in that the NCF is based on turbines located in a narrower area (versus a more regional approach taken for the other two sites).

[24] The conceptual capital costs for the 300 MW wind farms include estimated economies of scale associated with a larger wind facility. However, these economy of scale benefits may or may not be realized in actual project developments (some industry data suggests that the two sizes considered could carry similar costs on a $/kW basis).

Table 4.4-1. Conceptual On-Shore Wind Project Cost Estimates

Conceptual Capital Costs	Net Output	Major Equipment	BOP	Indirects	Subtotal - EPC	Owner's	AFUDC costs	Total Project Cost	Electric - Outside the Fence	Total with Interconnect
	MW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
100 MW Wind - Montana (Site #1)	100	$1,027	$128	$255	$1,410	$141	$85	$1,636	$86	$1,722
100 MW Wind - Montana (Site #2)	100	$1,027	$128	$255	$1,410	$141	$85	$1,636	$576	$2,212
100 MW Wind - Montana (Sites #3)	100	$1,027	$128	$255	$1,410	$141	$85	$1,636	$86	$1,722
100 MW Wind - Washington (Site #4)	100	$1,034	$128	$257	$1,420	$142	$85	$1,647	$103	$1,749
300 MW Wind - Montana (Sites #1 & #3)	300	$1,020	$111	$223	$1,354	$135	$81	$1,570	$46	$1,617
300 MW Wind - Montana (Site #2)	300	$1,020	$111	$223	$1,354	$135	$81	$1,570	$231	$1,802
300 MW Wind - Washington (Sites #4)	300	$1,028	$112	$226	$1,366	$137	$82	$1,585	$49	$1,633

The conceptual EPC cost includes the wind turbines, foundations, electrical systems up to the high side of the GSU transformers in the collector substation (excluding radial line, interconnection substation (as applicable), and transmission network upgrades). The turbines are assumed to be installed on land not owned by PSE resulting in an assumed land lease cost, which is not included in the capital costs.

AFUDC costs were estimated by PSE at 6% of the project EPC cost and are included in the table above. The opinion of probable owner's costs represented above can roughly be broken down into the following general cost categories.

Table 4.4-2. General Owner's Cost Categories

Opinion of Probable Owner's Costs		On-Shore Wind
Project Development/Management	%	2%
Execution Support	%	1%
Owner's Contingency	%	5%
Miscellaneous	%	2%
Total	%	10%

Table 4.4-3 provides assumptions and information related to outside the fence electrical infrastructure. For the purpose of this evaluation, Site #1 is assumed to be located about 5 miles from the Colstrip transmission line while Site #2 is assumed to be located approximately 75 miles from the line. Site #3 is assumed to interconnect to the local transmission system in the area and, consistent with the interconnection basis in this evaluation, is assumed to be located approximately 5 miles from the POI.

Table 4.4-3. Electrical Infrastructure Costs Outside the Fence

Plant Configuration	Nominal Installed Capacity (MW)	Radial Line /POI infrastructure	Cost ($ MM)			Cost ($/kW)
			Radial Line	POI infrastructure	Total	
Wind Montana Site #1	100	115 kV 5 mile lineto POI. Breaker and one half interconnection arrangment at POI	$3.5	$5.1	$8.6	$86
Wind Montana Site #2	100	115 kV 75 mile line to POI. Breaker and one half interconnection arrangment at POI	$52.5	$5.1	$57.6	$576
Wind Montana Site #3	100	115 kV 5 mile lineto POI. Breaker and one half interconnection arrangment at POI	$3.5	$5.1	$8.6	$86
Wind Washington Site #4	100	115 kV 5 mile line to POI. Breaker and one half interconnection arrangment at POI	$5.2	$5.1	$10.3	$103
Wind Montana Site #1 and #3	300	230 kV 5 mile radial line to POI. Breaker and one half interconnection arrangment at POI	$4.0	$9.9	$13.9	$46
Wind Montana Site #2	300	230 kV 75 mile radial line to POI. Breaker and one half interconnection arrangment at POI	$60.0	$9.4	$69.4	$231
Wind Washington Site #4	300	230 kV 5 mile radial line to POI. Breaker and one half interconnection arrangment at POI	$5.2	$9.4	$14.6	$49

4.5. Conceptual O&M Costs

Fixed O&M costs for wind farms include staffing and major turbine parts and maintenance costs, including replacement parts and labor to perform major maintenance.

Estimated first year fixed O&M costs for a proxy wind farm are summarized in the table below. There are typically no reported variable O&M costs associated with wind power generation as they are typically incorporated into the fixed O&M costs on a contractual basis.

Table 4.5-1. Conceptual On-Shore Wind O&M Costs

Conceptual O&M Costs	Fixed O&M	Variable O&M
	$/kW-yr	$/MWH
100 MW Wind	$37.00	-
300 MW Wind	$37.00	-

4.6. Project Implementation Schedule

Currently, wind farms have a timeline of nominally two years from contractor NTP through COD. It should be noted that timeline and vendor schedule could be influenced by seasonal and market variations. A project implementation schedule is included for the 100 MW configuration in Appendix A and a conceptual capital spend curve is included Appendix B. The EPC project schedule for a nominal 300 MW wind farm is expected to be similar to that of a 100 MW facility in the range of 20 to 26 months. Note that all site acquisition and project permitting activities are assumed to be completed prior to contractor NTP.

5. Off-Shore Wind technology

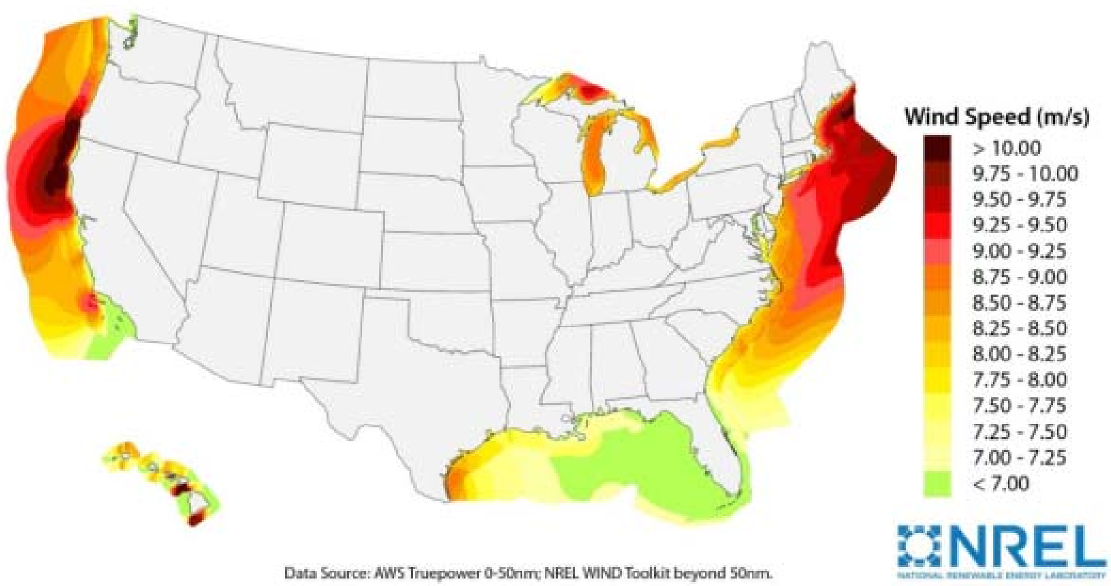
Recently, electricity production from off-shore wind farms has only been considered in theoretical examples or in overseas projects. This is primarily because over 90% of currently operating off-shore projects are in Europe. However, the technology is observing renewed interest from state governments, the independent project development community, and electric utility companies since the first U.S. off-shore wind farm[25] achieved commercial operation status in December, 2016. The U.S. has access to good off-shore wind resources in coastal states located along the Atlantic and Pacific Oceans and Great Lakes.

For this evaluation, a nominal 300 MW wind generation facility was examined for PSE as a representative proxy project size at an off-shore site approximately 3 miles off the coast of Washington.

5.1. Technology Overview

Like on-shore wind projects, off-shore wind turbines rely on the kinetic energy of wind to generate electricity. Figure 5.1-1 shows color-coded wind velocity data along the major coastlines of the U.S. As indicated, the off-shore wind velocities off the Washington coast are relatively average. Wind velocities increase further south along the coast to southern Oregon and northern California.

Figure 5.1-1. U.S. Wind Offshore Speeds at 100m Hub Height



[25] Block Island Wind Farm – 30 MW wind farm off the coast of Rhode Island.

A typical wind farm includes several wind turbines arranged in multiple rows and daisy-chained. Electricity generated from the wind turbines is collected in an off-shore collector (transformer) station that generally steps up power to a higher voltage for transmission back to shore. Special grade submerged sea cables are used extensively in off-shore wind applications to connect the individual turbines to the transformer station as well as the transformer station to the grid interconnection switchyard located on land. Subsea cables are installed and secured on to the ocean floor. Due to advances in technology, offshore wind farms are being located at increasing distances from the coast. Large scale wind farms are being developed in the 30 mile to 125 mile range from shore. Distance from land has an impact on cost including the design of subsea electrical cabling and system configuration. Noteworthy considerations for off-shore wind applications include the possible use of high-voltage direct current (HVDC) transmission to minimize losses, and logistical challenges and increased transportation time during construction and operation phases.

Another factor that has a considerable impact on off-shore wind farms is the turbine foundation design. Based on depth of the ocean floor and soil conditions, turbine substructures may employ one of several designs such as monopoles, jacket, gravity base, tripod, tri-pile, floating, spar-buoy, or tension leg platform designs (among others).

5.2. Commercial Status and Current Market

Relative to Europe, the U.S. off-shore wind market is nascent, but it appears to be gaining increased attention. Worldwide, the market is trending in the direction of installing larger capacity, high efficiency wind turbines. The 6 MW single unit turbine has replaced the older sub-3 MW unit, and newer designs in the 8 MW to 10 MW range are starting to emerge[26]. Larger capacity turbines may result in optimized capital and installation costs and overall reduced cost of generation for off-shore wind projects.

With the declining cost observed in European markets, the strong presence of experienced developers[27] in the United States, the emergence of new state-level policies that mandate off-shore wind energy procurement, and streamlining of permits and requirements by regulatory agencies, there is expected to be increased deployment of off-shore technology going forward.

[26] GE’s most recently announced turbine, Halide-X, is a 12 MW 260m tall wind turbine. The first demonstration project is expected to be complete in 2019 and turbines anticipated to be available by 2021.
[27] Prominent offshore wind developers such as DONG Energy, Statoil ASA, Iberdrola, Ørsted are all actively pursuing opportunities.

5.2.1. Current Market Influences

Recently, there has been significant activity at the state level to implement measures to mandate energy procurement from off-shore wind resources. Some of the state-level activity includes:

1. State of Massachusetts: Mandate of procuring energy from up to 1,600 MW of off-shore wind energy by 2027. May 2018, Vineyard Wind Project for 800 MW of off-shore wind energy was selected.
2. State of New Jersey: Mandate of procuring energy from 3,500 MW of off-shore wind by 2030.
3. State of New York: Published a "master plan" for developing the off-shore wind energy industry and reaching 2,400 MW of capacity by 2030.
4. State of Rhode Island: Selected Deepwater Wind to construct a new, 400 MW off-shore wind farm.

Additionally, the Federal PTC, as discussed in Section 5.2.1, has been instrumental in supporting the deployment and growth of wind energy in the U.S. However, this tax credit is not available for projects commencing construction after 2019.

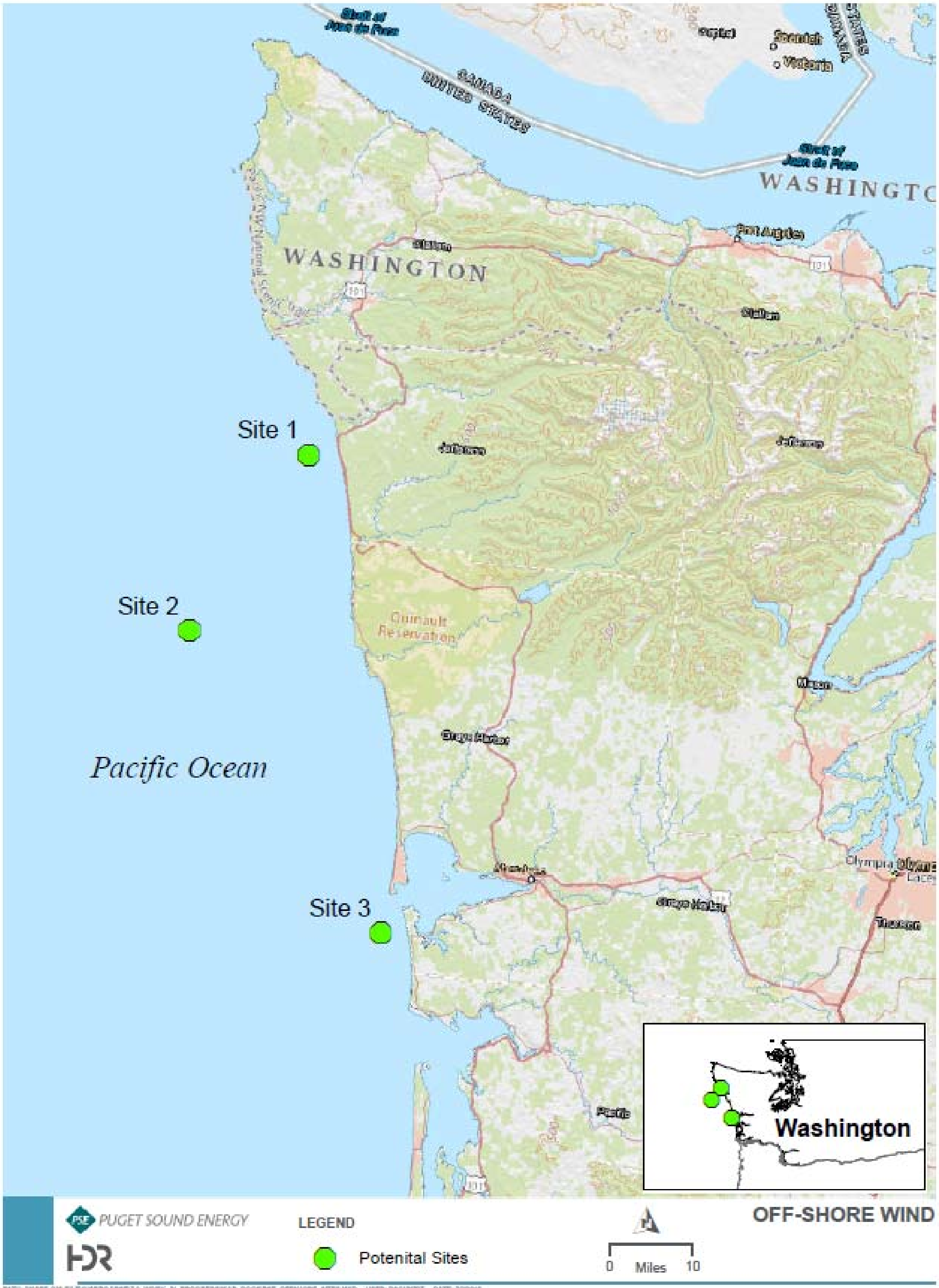
5.3. Operational Considerations

Wind farms are typically designed for a 20 year life. The operations and maintenance of off-shore wind farms can represent a significant proportion of the cost of energy for off-shore wind resources. Compared to on-shore wind, there is a substantial level of added complexity to major repair and replacements of off-shore wind farm components due to the logistical complexity of the ocean environment and scarcity of required special ocean maintenance vessels. Scheduled maintenance is also impacted due to uncertainty over the finite access timelines, wave heights, water depths, and distance from shore.

5.3.1. Performance Data

The following map indicates location of several potential proxy locations identified using the NREL WIND Toolkit.

Figure 5.3-1. Potential Off-Shore Wind Farm Sites in Washington



Considering wind resource data from NREL, an annual average NCF was estimated for each of the sites considered. The estimated NCFs as well as nominal site attributes are summarized in the table below.

Table 5.3-1. Off-Shore Wind Estimated NCFs (at 150m Hub Height) and Site Assumptions

Off-Shore Wind Performance	NCF	Distance from Shore	Ocean Depth
	%	miles	feet
Site #1	31.1%	10	30
Site #2	35.0%	15	400
Site #3	35.3%	~3	60

5.4. Conceptual Cost Estimate

Based on the assumptions outlined herein, the planning level conceptual capital cost estimate for a nominal 300 MW off-shore wind farm is summarized in the table below.

Table 5.4-1. Conceptual Off-Shore Wind Project Costs

Conceptual Capital Costs	Net Output	Major Equipment	BOP	Indirects	Subtotal - EPC	Owner's	AFUDC costs	Total Project Cost	Electric - Outside the Fence	Total with Interconnect
	MW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
300 MW Off-Shore Wind (WA)	300	$1,505	$2,940	$555	$5,000	$930	$550	$6,480	$67	$6,547

The conceptual EPC cost includes the wind turbines, fixed monopole foundations, and electrical systems including subsea cables connecting the transformer station 3 miles off-shore to the interconnection substation on-shore. A summary report indicating the proxy off-shore wind farm concept and an opinion of costs for subsea cables is included as Appendix D to this report.

AFUDC costs were estimated by PSE at 11% of the project EPC cost and is included in the table above. The opinion of probable owner's costs represented above can roughly be broken down into the following general cost categories.

Table 5.4-2. General Owner's Cost Categories

Opinion of Probable Owner's Costs		Off-Shore Wind
Project Development/Management	%	5%
Execution Support	%	1%
Owner's Contingency	%	7%
Miscellaneous	%	3%
Total	%	16%

Table 5.4-3 provides assumptions and information related to outside the fence electrical infrastructure.

Table 5.4-3. Electrical Infrastructure Costs Outside the Fence

Plant Configuration	Nominal Installed Capacity (MW)	Radial Line /POI infrastructure	Cost ($ MM)			Cost ($/kW)
			Radial Line	POI infrastructure	Total	
Off Shore Wind	300	230 kV 5 mile line to POI. Breaker and one half interconnection arrangment at POI	$9.8	$10.4	$20.2	$67.2

5.5. Conceptual O&M Costs

Several operating plants are within the warranty period/contracted with turbine vendors for performing maintenance of the turbines. As such, there is a lack of operational data available in the public domain, resulting in general uncertainty on O&M costs for off-shore wind farms.

The emerging nature of the industry in the U.S. also means that there is an acute shortage of experienced personnel for performing O&M activities. Some of the primary influences of off-shore wind farm annual O&M costs include: availability of an ocean-going vessel, component scheduled/unscheduled maintenance (gearbox, generator, controls and monitoring system, blade), labor costs, port docking fees, land based support, and administration.

Estimated first year fixed O&M costs for a proxy 300 MW off-shore wind farm are summarized in the table below. There are typically no reported variable O&M costs associated with wind power generation as they are typically incorporated into the fixed O&M costs on a contractual basis.

Table 5.5-1. Conceptual Off-Shore Wind O&M Costs

Conceptual O&M Costs	Fixed O&M	Variable O&M
	$/kW-yr	$/MWH
300 MW Off-Shore Wind	$120.00	$0.00

5.6. Project Implementation Schedule

Off-shore wind farms typically experience long project development cycles. A number of factors, including weather, can influence construction activities post contractor NTP. For planning purposes, a typical fixed platform 300 MW wind farm could achieve COD within approximately 36 months from contractor NTP. A project implementation schedule is included in Appendix A and a representative capital spend curve is included in Appendix B.

6. Solar Photovoltaic (PV) Technology

For the purpose of this study, nominal 25 MW (AC) and 100 MW (AC) single axis tracking solar facilities were analyzed at a proxy site near Yakima, Washington.

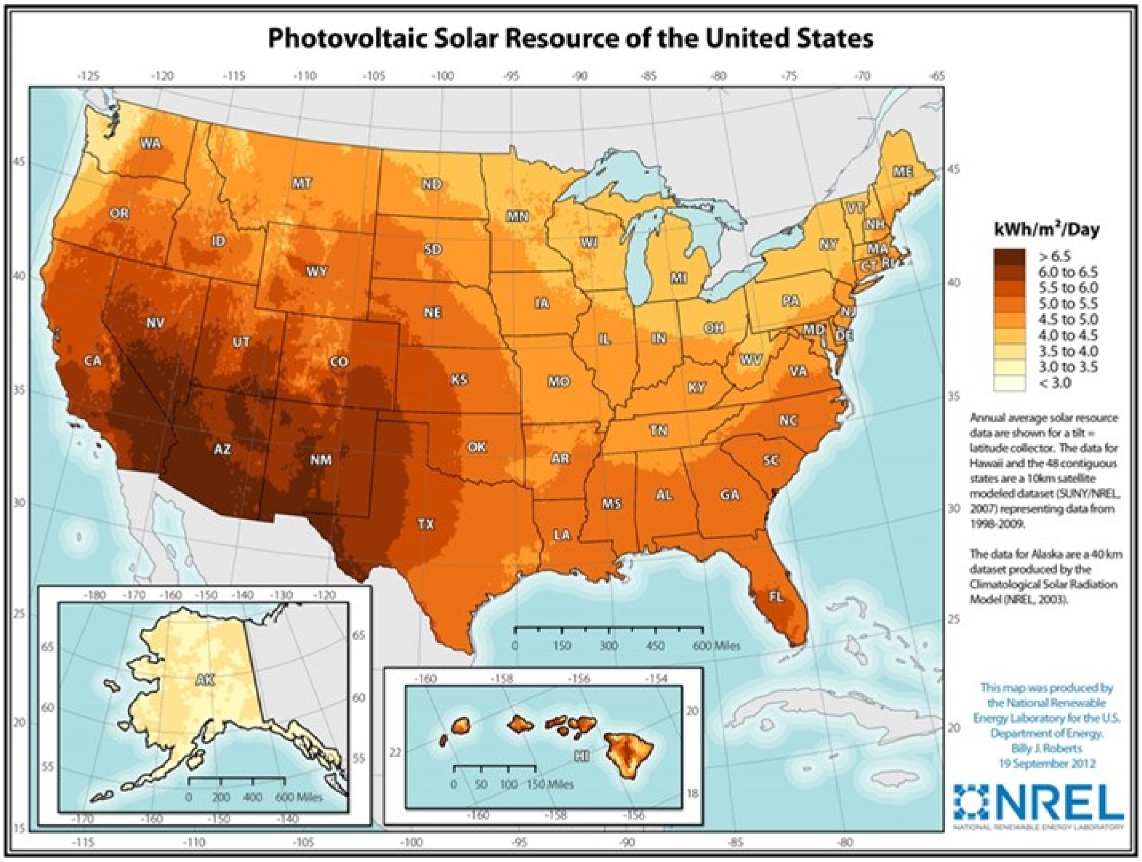
6.1. Technology Overview

Solar PV technology uses solar cells or PV arrays to convert light from the sun directly into electricity. PV cells are made of different semiconductor materials and come in many sizes, shapes, and ratings. Utility scale PV technologies are generally mono/poly silicon or thin film. Solar cells produce direct current (DC) electricity and therefore require a DC to alternating current (AC) converter (inverter) to allow for grid-connected installations.

The PV arrays are mounted on structures that can either tilt the PV array at a fixed angle or incorporate tracking mechanisms that automatically move the panels to follow the sun across the sky. The fixed angle is determined by the local latitude, orientation of the structure, and electrical load requirements. Tracking systems provide more energy production than fixed axis configurations. Single-axis trackers are designed to track the sun from east to west and dual-axis trackers allow for modules to remain pointed directly at the sun throughout the day. This evaluation considers a single-axis tracking configuration.

The amount of electricity produced from PV cells depends on the quantity and quality of the light available and performance characteristics of the PV cell. The largest PV systems in the country are located in the Southwestern regions where, as shown in Figure 6.1-1, the strongest solar resources are available.

Figure 6.1-1. United States Photovoltaic Solar Resource



6.2. Commercial Status and Current Market

PV cells are commercially available, mature technology with a significant installed operating base.

6.2.1. Current Market Influences

The Federal Investment Tax Credit (ITC) has been instrumental in supporting the deployment and growth of solar energy in the U.S. The ITC currently offers a 30% tax credit towards the investment cost of solar systems. For a solar project to get the 30% ITC, it must begin construction by December 31, 2019, but it does not have to go into service until December 31, 2023. The percentage steps down to 26% and 22% for projects that start construction in 2020 in 2021, respectively. For all scenarios where a solar project receives greater than a 10% ITC, the project must be placed into service by December 31, 2023. A summary of the Federal ITC phase down is provided in the table below.

Table 6.2-1. Federal ITC Phase Down for Solar PV[28]

Federal ITC Phase Down								
Year Construction Begins	2016	2017	2018	2019	2020	2021	2022	Future
Solar ITC	30%	30%	30%	30%	26%	22%	10%	10%

Recently, the U.S. imposed a 30% tariff on imported crystalline-silicon solar cells and modules that went into effect February 7, 2018. The tariffs start at 30% of the cell price in 2018 and then gradually drop to 15% by February 7, 2021. Per SEIA, the 30% tariff can be expected to increase year 1 PV module prices by roughly $0.10/W or $100/kW.

6.3. Operational Considerations

The single-axis tracking PV installation considered for this evaluation is for 25 MW (AC) of nameplate capacity. As such, it is envisioned that approximately 10 arrays of 2.5 MW (AC) each would be installed. Each array would consist of about 8,764 modules of 370 Wp capacity each. The land area required for this application would be extensive depending on a variety of factors including the land and design, but could roughly require 125 to 175 acres of land to support the capacity. A nominal 100 MW (AC) single-axis tracking solar PV installation is estimated to occupy a land area approximately four times of that needed for a 25 MW (AC) installations.

The major components included in the PV system include the PV modules/arrays, DC to AC converters/inverters, and mounting structures.

6.3.1. Performance Data

A proxy solar site was assumed to be located at a generic site in Yakima, Washington. An average capacity factor range for a solar power facility is typically in the range of 10 to 30 percent, with annual averages around 25 percent depending upon solar resources within the region. The estimated annual average NCF[29] is summarized in the table below. This NCF was estimated using NREL's PVSyst program. Annual degradation of energy production from solar PV systems is a known phenomenon. This is primarily the result of reduced solar module performance. Typical energy production degradation rates are in the range of 0.5 percent to 1.0 percent per year.

Table 6.3-1. Estimated Solar Site NCF

Estimated Solar PV Annual Average NCF		
Washington	%	24

[28] https://www.energy.gov/savings/business-energy-investment-tax-credit-itc

[29] Capacity factor for a generic site in Yakima, Washington area considered

6.3.2. Staffing Requirements

Staffing for a solar PV installation generally assumes the utilization of a remote monitoring/operating system. The majority of the staff is typically associated with maintenance and cleaning of the solar fields. Typical staffing requirements are minimal and, for the purpose of this analysis, include one salaried and two hourly staff.

6.4. Conceptual Capital Cost Estimate

Table 6.4-1 summarizes the estimated total project costs for a single-axis solar PV facility located in Washington for both 25 MW and 100 MW configurations. The project capital costs are based on overnight turnkey EPC delivery in 2018 dollars where the EPC contractor procures the major equipment. The estimated solar project cost includes the modules, structures, inverters, the balance of the system, and engineering and management services.

Table 6.4-1. Conceptual Solar PV Project Costs

Conceptual Capital Costs	Net Output	Major Equipment	BOP	Indirects	Subtotal - EPC	Owner's	AFUDC costs	Total Project Cost	Electric - Outside the Fence	Total with Interconnect
	MW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
25 MW Solar PV (WA)	25	$817	$149	$386	$1,352	$150	$41	$1,543	$380	$1,922
100 MW Solar PV (WA)	100	$813	$173	$352	$1,338	$134	$40	$1,512	$103	$1,614

AFUDC costs were estimated by PSE at 3% of the project EPC cost and is included in the table above. The opinion of probable owner's costs represented above can roughly be broken down into the following general cost categories.

Table 6.4-2. General Owner's Cost Categories

Opinion of Probable Owner's Costs		Solar PV
Project Development/Management	%	2%
Execution Support	%	1%
Owner's Contingency	%	5%
Miscellaneous	%	2%
Total	%	10%

Table 6.4-3 provides assumptions and information related to outside the fence electrical infrastructure.

Table 6.4-3. Electrical Infrastructure Costs Outside the Fence

Plant Configuration	Nominal Installed Capacity (MW)	Radial Line /POI infrastructure	Cost ($ MM)			Cost ($/kW)
			Radial Line	POI infrastructure	Total	
Solar PV Single Axis	25	115 kV 5 mile line to POI. Breaker and one half interconnection arrangment at POI	$5.2	$4.3	$9.5	$379.6
Solar PV Single Axis	100	115 kV 5 mile line to POI. Breaker and one half interconnection arrangment at POI	$5.2	$5.1	$10.3	$102.7

6.5. Conceptual O&M Costs

Estimated first year fixed O&M costs for proxy 25 MW and 100 MW single-axis tracking solar facilities are summarized in the table below. There are typically no reported variable O&M costs associated with solar power generation. Operation and maintenance costs are inclusive of plant staffing and major equipment parts and maintenance costs, including replacement parts and outsourced labor to perform major maintenance.

Table 6.4-2. Conceptual Solar PV O&M Costs

Conceptual O&M Costs	Fixed O&M	Variable O&M
	$/kW-yr	$/MWH
25 MW Solar	$27.19	-
100 MW Solar	$21.90	-

6.6. Project Implementation Schedule

Currently, solar PV installations have a timeline of approximately one year from EPC NTP through COD. A project implementation schedule is included in Appendix A and a representative capital spend curve is included in Appendix B.

7. Biomass Generation Resource

Biomass power production is a 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 exist for combustion in a biomass power plant. The main fuel sources for solid biomass plants are woody biomass material sources from sustainable forestry practices, wood chips from lumbering operations, byproducts from sawmills and process industries, 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 15 MW wood burning biomass steam plant has been considered with the following features:

- 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

7.1. Technology Overview

Biomass plants operate based on the traditional Rankine cycle that governs the operation of steam power plants. A biomass fuel, such as wood chips, is burned in a large boiler or steam generator, which produces steam for electric production in a steam turbine generator. For this evaluation, the CFB boiler was paired with a single stage steam turbine and a water-cooled condenser using a wet cooling tower.

7.2. Commercial Status and Current Market

Biomass power production is a 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 U.S. One of the major considerations for a biomass power station is the reliable year-round availability of biomass fuel at acceptable prices enabling their long term economic feasibility. Biomass power plants currently installed in the U.S. range from less than 5 MW of output up to 150 MW of output.

7.3. Operational Considerations

7.3.1. Fuel Assumptions

The composition of the assumed biomass fuel is shown below in Table 7.3-1.

Table 7.3-1. Representative Biomass Fuel Composition

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	%

7.3.2. Plant Performance

Overall estimated new and clean net plant outputs and net plant heat rates are depicted for a 15 MW CFB biomass plant in Tables 7.3-2 and 7.3-3 for summer and winter ambient conditions, respectively.

Table 7.3-2. Estimated Biomass Summer Performance

Summer Peformance	Summer Peak 100%		Summer Average 100%	
	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)
	kW	Btu/kWh	kW	Btu/kWh
15 MW Biomass	14,421	14,972	14,955	14,415

Table 7.3-3. Estimated Biomass Winter Performance

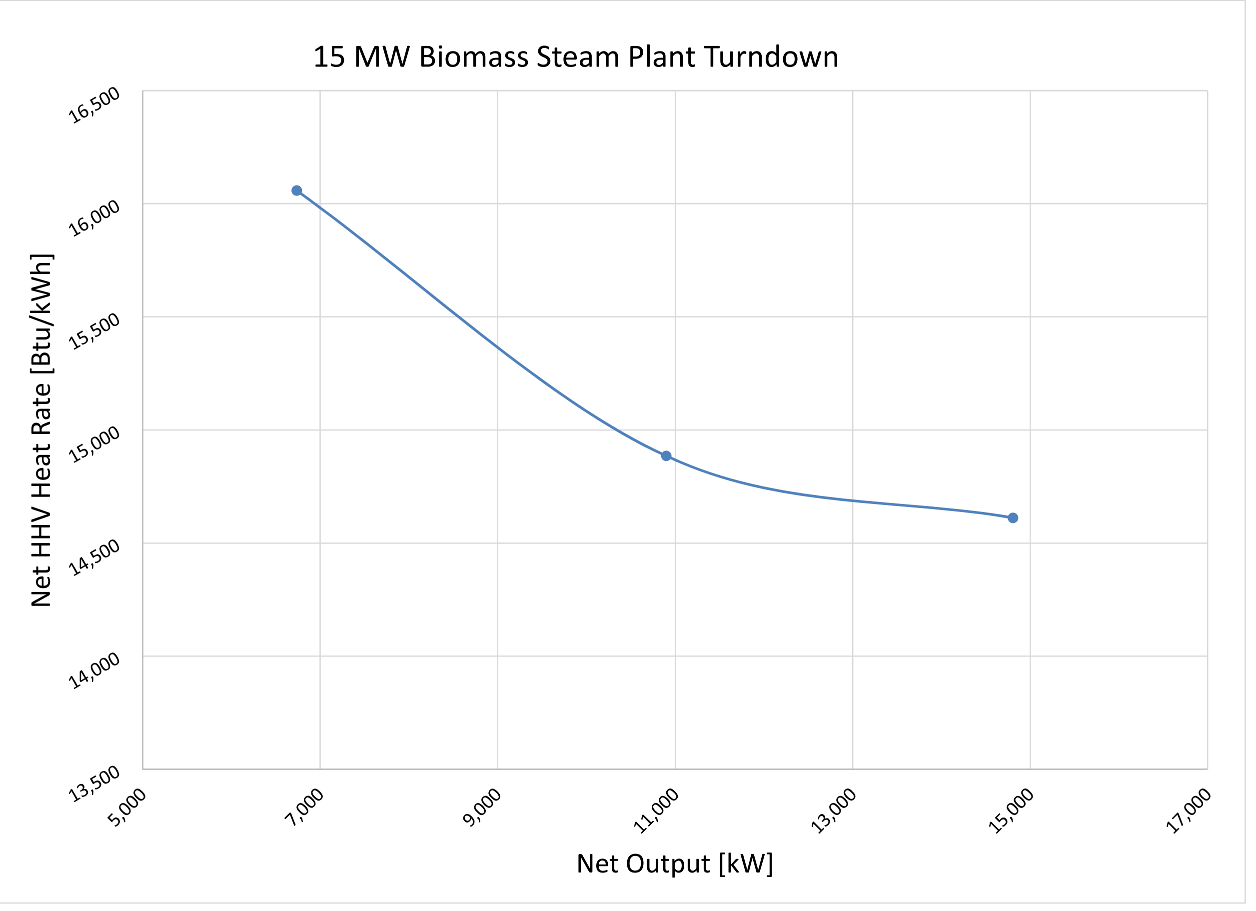
Winter Performance	Winter Average 100%		Winter Peak 100%	
	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)
	kW	Btu/kWh	kW	Btu/kWh
15 MW Biomass	15,112	14,317	15,271	14,154

As part of this analysis, heat rate curves for unit turn down from 100% load to MECL were estimated for the biomass plant based on operation at ISO conditions. Table 7.3-4 tabulates the turn down performance used to generate the heat rate curves for this technology. Figure 7.3-1 graphically depicts plant performance as a function of load.

Table 7.3-4. Estimated Biomass ISO Performance

ISO Performance	ISO 100%		ISO 75%		ISO MECL	
	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)
	kW	Btu/kWh	kW	Btu/kWh	kW	Btu/kWh
15 MW Biomass	14,805	14,599	10,900	14,873	6,736	16,045

Figure 7.3-1. 15 MW Biomass Steam Plant Turn Down



Other operating characteristics of the biomass steam generation resource include ramp rate, minimum run times, minimum down times, and startup times. These characteristics are summarized for a 15 MW biomass steam generation resource in the table below. The following assumptions and clarifications pertain to Table 7.3-5:

- 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 actual operating preferences.

Table 7.3-5. Operational Characteristics

Configuration		Biomass
Ramp Rate	MW /min	2
Minimum run time	min	240
Minimum down time	min	60
Start-up time to full load at warm start	min	240
Start-up time to full load at cold start	min	360

7.3.3. Environmental Considerations

EMISSIONS

The expected controlled emissions for the 15 MW biomass plant are summarized in Table 7.3-6. 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 below are based on the biomass fuel composition described in Section 7.3.1. Actual emissions could vary depending on composition of the biomass fuel.

Table 7.3-6. 15 MW Biomass Estimated Emissions

Estimated Emissions	Heat Input	Net Output	NOx	PM	SO2	CO	VOC	CO2
	mmbtu/hr	MW	lb/mmbtu	lb/mmbtu	lb/mmbtu	lb/mmbtu	lb/mmbtu	lb/mmbtu
15 MW Biomass	216	15	0.0290	0.0540	0.0320	0.3000	0.0014	213

WATER CONSUMPTION / WASTEWATER DISCHARGE

The main water consumption for this technology is the wet cooling tower used to supply cooling water to the condenser. The plant would 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 7.3-7.

Table 7.3-7. 15 MW Biomass Estimated Plant Water Consumption/Wastewater Discharge

Estimated Water Consumption / Wastewater Discharge (Summer)	Summer Peak		Summer Average	
	Water Consumption	Wastewater Discharge	Water Consumption	Wastewater Discharge
	gal/MWH	gal/MWH	gal/MWH	gal/MWH
15 MW Biomass	1,061	214	769	156

7.4. Conceptual Capital Cost Estimate

Based on the assumptions and basis outlined herein, Table 7.4-1 summarizes the estimated total project costs for a proxy 15 MW biomass steam plant.

Table 7.4-1. Conceptual Biomass Project Costs

Conceptual Capital Costs	Winter Peak Net Output	Major Equipment	BOP	Indirects	Subtotal - EPC	Owner's	AFUDC costs	Total Project Cost	Electric - Outside the Fence	Total with Interconnect
	MW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
15 MW Biomass	14.90	$2,468	$2,173	$2,395	$7,036	$1,116	$915	$9,067	$628	$9,695

AFUDC costs were estimated by PSE at 13% of the project EPC cost and are included in the table above. The opinion of probable owner's costs represented above can roughly be broken down into the following general cost categories.

Table 7.4-2. General Owner's Cost Categories

Opinion of Probable Owner's Costs		Biomass
Project Development/Management	%	2%
Execution Support	%	1%
Owner's Contingency	%	10%
Miscellaneous	%	1%
Total	%	14%

Table 7.4-3 provides assumptions and information related to outside the fence electrical infrastructure.

Table 7.4-3. Electrical Infrastructure Costs Outside the Fence

Plant Configuration	Nominal Installed Capacity (MW)	Radial Line /POI infrastructure	Cost ($ MM)			Cost ($/kW)
			Radial Line	POI infrastructure	Total	
Biomass Combustion	15	115 kV 5 mile line to POI. Breaker and one half interconnection arrangment at POI	$5.2	$4.2	$9.4	$624.0

7.5. Conceptual O&M Costs

The estimated fixed and variable O&M costs for a 15 MW biomass plant are summarized in Table 7.5-1 assuming a base load dispatch profile. O&M costs are inclusive of steam generator, steam turbine, BOP 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 are anticipated to require 9 salaried and nineteen hourly staff.

Table 7.5-1. Conceptual Fixed and Variable O&M Costs

Conceptual O&M Costs	Fixed O&M	Variable O&M
	$/kW-yr	$/MWH
15 MW Biomass	$345.20	$6.60

7.6. Project Implementation Schedule

The estimated project schedule for a nominal 15 MW biomass steam generating plant is 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 contractor NTP. A 15 MW CFB biomass plant can be expected to take 3 to 4 years to construct from EPC NTP to the COD. A project implementation schedule is included in Appendix A and a representative capital spend curve is included in Appendix B.

8. Pumped Hydro Energy Storage (PHES)

Pumped hydro energy storage (PHES) facilities store potential energy in the form of water in an upper reservoir, pumped from another reservoir at a lower elevation. In these facilities, the water is pumped uphill during periods of low energy demand and cost such as during the night or over the weekend. The stored water is released to flow downhill through pump-turbines in the same manner as a conventional hydro station to produce energy during periods of high electricity demand.

Reversible pump-turbine/generator-motor assemblies can act as both pumps and turbines. Pumped storage stations are a net consumer of electricity, due to hydraulic and electrical losses incurred in the cycle of pumping from the lower reservoir to the upper reservoir. However, these plants typically perform well economically, capturing peak to off-peak energy price differentials, and providing ancillary services to support the overall electric grid.

A 500 MW, 4,000 MWh and 300 MW, 2,400 MWh slice of two larger closed loop PHES facility sites have been considered for this study. The concept presented here assumes PSE taking ownership of a slice of a larger PHES project in the U.S. Pacific Northwest.

8.1. Technology Overview

PHES is regarded as a mature technology, but does require available topography and water availability.

The generating equipment for the majority of the existing pumped storage plants in the U.S. is the reversible, single-stage Francis pump-turbine. All of the major equipment vendors have significant experience with this type of unit. The technology for single-stage units continues to advance, and a broad range of equipment configurations are available depending upon the available head, site layout, and desired operation.

Variable speed pump-turbines have been used since the early to mid-1990’s in Japan and late 1990’s in Europe. They are being increasingly considered during project development in Europe and Asia due to a high percentage of renewable energy penetration and the need for load following, ramping, and frequency regulation during periods of excess generation. In California and Arizona, three large pumped storage projects in development are considering variable speed technology almost exclusively due to the growing need for decremental reserves during the day, enabling greater penetration of variable renewable energy resources.

PHES technology is considered partially dispatchable (limited based on reservoir volume) and generally possesses the operational flexibility to provide ancillary services.

8.2. Commercial Status and Current Market

The first U.S. pumped-storage plant was commissioned in 1929 to help balance the grid. Today, there are approximately 40 pumped storage projects operating in the U.S and pumped energy storage is considered commercially available and mature as many plants were installed throughout the U.S. in the 1970’s and 1980’s.

PHES can consist of either open-loop or closed-loop projects, with both types currently operating in the U.S. The distinction between closed-loop and open-loop pumped storage projects is typically defined as:

- Closed-loop pumped storage are projects that are not continuously connected to a naturally flowing water feature; and
- Open-loop pumped storage are projects that are continuously connected to a naturally-flowing water feature.

Closed-loop systems are preferred for new developments as there are often significantly fewer environmental issues, primarily due to the lack of aquatic resource impacts. Projects that are not strictly closed-loop systems can also be desirable, depending upon the project configuration, and whether the project uses existing reservoirs.

8.3. Operational Considerations

A PHES site requires an adequate geology, the potential to create two reservoirs, and acceptable geography. For the purpose of this study, 500 MW and 300 MW PHES resources, both with 8 hours of dispatch capability and both assumed to be a slice of a larger project, were assumed.

A pumped storage project would typically be designed to have between 6 to 20 hours of hydraulic reservoir storage for operation at full generating capacity. By increasing plant capacity in terms of size and number of units, hydroelectric pumped storage generation can be concentrated and shaped to match periods of highest demand, when it has the greatest value. Existing pumped storage projects range in capacity from 9 to 2,700 MW, and in available energy storage from 87 MWh to 370,000 MWh of storage.

Water-to-wire efficiencies vary based on individual equipment designs, age of the project, and site hydraulics, and include the pump-turbine, generator-motor and transformer efficiencies. Water-to-wire efficiency is typically near 85 – 90 percent for pumping mode and approximately 88 percent generating mode for fixed speed Francis pump-turbines, resulting in a turnaround or cycle efficiency of approximately 80 percent.

8.3.1. Performance Data

Table 8.3-1 summarizes estimated performance data for the two PHES configurations considered in this evaluation.

Table 8.3-1. Conceptual PHES Performance Characteristics

Conceptual PHES Performance			
Net Capacity	MW	500	300
Maximum MW	MW	500	300
Generating Mode Minimum MW			
At Minimum Head	MW	183	139
At Maximum Head	MW	111	86
At Average Head	MW	147	112.5
Pumping Mode Minimum MW			
At Minimum Head	MW	354	278
At Maximum Head	MW	401	315
At Average Head	MW	378	297
Pumping Mode Maximum MW			
At Minimum Head	MW	517	406
At Maximum Head	MW	517	406
Discharge Duration	Hours	8	8
Net Turnaround Efficiency	%	80	80
Forced Outage Rate	%	1	1
Economic Life	Years	30+	30+

Table 8.3-1 includes operational characteristics for both generating and pumping modes. For the 500 MW PHES configuration, a unit could generate between a minimum of 111 MW to 183 MW (depending on the head levels), and then in pumping mode be capable of starting at a minimum input power of 354 MW to 401 MW (depending on the head) at low speed, and then ramp up to a maximum input power of 517 MW at high speed as necessary to support grid operations. There is no minimum time requirement in either pumping or generating mode. An estimate of the amount of time to switch between generating and pumping modes is provided in Table 8.3-2 below.

Table 8.3-2. General Operational Characteristics

Mode	Duration
Full Generation to Standstill	< 210 seconds
Standstill to Full Generation	<90 seconds
Full Pump to Standstill	<90 seconds
Standstill to Full Pump	<240 seconds
Full Generation to Full Pump	<480 seconds
Full Pump to Full Generation	<275 seconds

8.3.2. Staffing Requirements

Based on existing units in operation and recent project developments, staffing for a 500 MW or 300 MW PHES facility is estimated to require approximately 25 to 30 staff.

8.4. Conceptual Capital Cost Estimate

Conceptual project capital costs for the two configurations considered in this evaluation are summarized in Table 8.4-1.

Table 8.4-1. Conceptual Pumped Hydro Storage Costs

Conceptual Capital Costs	Net Output	Major Equipment	BOP	Indirects	Subtotal - EPC	Owner's	AFUDC costs	Total Project Cost	Electric - Outside the Fence	Total with Interconnect
	MW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
500 MW PHES (Slice)	500	$723	$775	$302	$1,800	$452	$360	$2,612	$49	$2,661
300 MW PHES (Slice)	300	$723	$775	$302	$1,800	$452	$360	$2,612	$67	$2,679

AFUDC costs were estimated by PSE at 20% of the project EPC cost and is included in the table above. The opinion of probable owner's costs represented above can roughly be broken down into the following general cost categories.

Table 8.4-2. General Owner's Cost Categories

Opinion of Probable Owner's Costs		PHES
Project Development/Management	%	5%
Execution Support	%	2%
Owner's Contingency	%	12%
Miscellaneous	%	3%
Total	%	22%

Table 8.4-3 provides assumptions and information related to outside the fence electrical infrastructure.

Table 8.4-3. Electrical Infrastructure Costs Outside the Fence

Plant Configuration	Nominal Installed Capacity (MW)	Radial Line /POI infrastructure	Cost ($ MM)			Cost ($/kW)
			Radial Line	POI infrastructure	Total	
Pumped Hydro Storage	500	230 kV 5 mile line to POI. Breaker and one half interconnection arrangment at POI	$9.8	$15.0	$24.7	$49.4
Pumped Hydro Storage	300	230 kV 5 mile line to POI. Breaker and one half interconnection arrangment at POI	$9.8	$10.4	$20.2	$67.2

8.5. Conceptual O&M Costs

Operations and maintenance costs for PHES have been estimated assuming a daily dispatch profile with approximately 8 hours of electric production daily utilizing Electric Power Research Institute (EPRI) established calculation methodology. The fixed and variable O&M estimated costs for a 500 MW and 300 MW pumped hydro plant are summarized in Table 8.5-1. O&M costs are inclusive of staffing, turbine, generator, and balance of plant and facility routine maintenance and major overhaul costs. No royalty or land lease fees are included in these costs. 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.

The estimated fixed and variable O&M costs are based on work for recent confidential pumped storage projects, established EPRI calculation methodology, and comparable industry data. Variable O&M costs also account for the anticipated number of starts and stops per day.

Table 8.5-1. Conceptual PHES O&M Costs

Conceptual O&M Costs	Fixed O&M	Variable O&M
	$/kW-yr	$/MWH
500 MW PHES	$14.55	$0.90
300 MW PHES	$17.40	$1.50

8.6. Project Implementation Schedule

The schedule for a PHES plant can vary considerably depending on a number of factors including the amount of civil work required to establish the water storage basins and the permitting required to implement the project. The total construction time from receipt of FERC license to commercial operation can be anywhere from 5 years to 8 years for projects similar to that evaluated herein.

9. Battery Energy Storage System (BESS)

Grid-connected battery energy storage systems (BESS) are maturing, with increasing commercial deployment in the electric industry.

BESS may be considered to meet overall electricity demands by the electric utility or to help minimize peak demand, smooth load variations due to renewables integration, and for improving local grid resilience and availability.

9.1. Technology Overview

Lithium Ion (Li-ion) batteries utilize the exchange of lithium ions between electrodes to charge and discharge the battery. When the battery is in use (discharge) the charged electrons move from the anode to the cathode and in the process, energize the circuit that it is connected to. Electrons flow in the reverse direction during a charge cycle when energy is drawn from grid. Due to its characteristics, Li-ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term spinning reserve applications. Additionally, compared to other BESS, the Li-ion technology provides the highest energy storage density resulting in its adoption in several different markets ranging from consumer electronics to transportation (electric vehicles) and power generation.

Vanadium redox flow batteries are based on the redox reaction between electrolytes in the system. The system consists of two liquid electrolytes in tanks (vanadium ions in different oxidation states) separated by a proton exchange membrane. The membrane permits ion flow but prevents mixing of the liquids. Electrical contact is made through inert conductors in the liquids. As the ions flow across the membrane, an electrical current is induced in the conductors to charge the battery. This process is reversed during the discharge cycle. The liquid electrolyte used for charge-discharge reactions is stored externally and pumped through the cell. A typical vanadium redox flow battery includes large electrolyte storage tanks and pumps limiting this technology to certain applications.

9.2. Commercial Status and Current Market

Li-ion battery technology is a relatively mature technology, having been first proposed in 1970 and released commercially in 1991. The market for utility-scale energy storage systems is relatively early in development, but it is growing and evolving quickly.

The increasing demand for battery storage in consumer electronics and the transportation sector as well as the emerging demand from the energy sector is propelling advances in the technology and manufacturing capacity for Li-ion. This is also aiding the trend of declining initial capital cost for this technology.

While the first successful demonstration project for a vanadium redox flow battery system was in the 1980’s, today, there are only a few systems in operation worldwide. The vanadium redox flow industry is moving towards pre-packaged systems in containers to better compete with Li-ion systems. There is significant interest in these vanadium redox flow systems as they have a high cycle life, have a large allowable temperature range, and longer storage durations.

Other battery storage technologies include sodium sulfur, lead-acid, zinc iron and zinc bromine flow technologies; however, Li-ion is the most prominent and widely used for utility scale BESS. This is primarily due to technology maturity and risks that are better understood, the number of established and credit worthy Li-ion battery manufacturers in the market place, their ability to provide long term performance guarantees and warranties typically required by the electric utility industry, and the existence of reliable integrators that have a successful track record of installing turnkey EPC BESS projects for several years.

9.2.1. Current Market Influences

FERC ORDER 841

On February 15, 2018 the Federal Energy Regulatory Commission (FERC) issued FERC Order 841 that directs the operators of wholesale markets, Regional Transmission Organizations (RTO) and Independent System Operators (ISO) to develop market rules for energy storage to participate in wholesale energy, capacity, and ancillary service markets. The order essentially allows an energy storage resource to be dispatched and to be able to set market clearing places as both a buyer and seller. RTOs and ISOs have nine months to file tariffs that comply with the order and another year to implement the tariff provisions.

The FERC Order essentially removes the barriers for market entry and levels the playing field for BESS with other resources. However, how the RTOs implement Order 841 will affect a storage system's market value and adoption rate.

STATE ENERGY STORAGE PROGRAMS AND INITIATIVES

In the last few years there has been considerable activity at the state level to implement measures to encourage the integration of BESS resources. Some of the examples of state-level activity include:

- State of Oregon – Mandate of 5 MW per utility
- State of California – Mandate of 1,325 MW by 2020; new IRP in 2018 suggests an additional 2,000 MW
- State of Arizona – 3,000 MW target energy storage proposed by State Corporation Commission
- State of Massachusetts – Mandate of 200 MWh by 2020
- State of New York – Governor proposed 1,500 MW storage by 2025
- State of Nevada – Legislation requires the Public Utilities Commission (PUC) to investigate storage targets

Additionally, several states including Maryland, North Carolina, Ohio, Vermont, Indiana, Minnesota, Illinois, Colorado, New Mexico, and Washington are among others where active proceedings and regulatory discussions are underway on the topic of grid modernization, distributed energy and energy storage.

9.3. Operational Considerations

For this study, the following configurations were considered:

1. Li-ion BESS – 2 discharges per day
    a. 25 MW with 2 hours of storage
    b. 25 MW with 4 hours of storage
2. Vanadium Redox Flow BESS – 2 discharges per day
    a. 25 MW with 4 hours of storage
    b. 25 MW with 6 hours of storage

The basis of capacity sizing and dispatch capability was determined by PSE to provide dispatch capability enabling demand management/load shifting as well as local restoration efforts in the case of outage conditions.

Numerous BESS integrators in the marketplace were contacted[30] to collect technical and commercial data. Technical information as well as experience, scope of supply, schedule of delivery, pricing and O&M details were solicited from the integrators that responded. Information received was specific to Li-ion technology, largely due to its experience in the industry. Some information was also gathered from vanadium redox flow battery integrators.

Major components of a BESS station include:

- The battery containers
- Battery management system (BMS)
- Power conversion system (PCS) enclosures
- Plant control systems
- BOP systems including the cooling system, station load transformers, pad mounted medium/high voltage transformers, and grid interconnection gear with metering, site utilities, foundations and plant fencing

9.3.1. Performance Data

Table 9.3-1 summarizes estimated performance data for a typical 25 MW BESS based on the storage capacity.

[30] Greensmith Energy, ABB Inc., Renewable Energy Systems Americas Inc., S&C Electric Company, AES Energy Storage, Uni Energy Technologies, ViZn Energy Systems, Vinox Energy and Primus Power.

Table 9.3-1. BESS Performance Comparison

Parameter/Technology	Lithium Ion		Vanadium Redox Flow	
Capacity (MW)	25	25	25	25
Max Storage Limit (MWh)	50	100	100	150
Min Storage Limit (MWh)	2	2	2	2
Leakage Rate (% /hr)	0.05%	0.05%	0.00%	0.00%
Discharge Duration (hrs)	2	4	4	6
Recharge Time (hrs)	2.5	4.5	4.5	6.5
Round Trip Efficiency	82%	87%	73%	73%
Cycle Life (2 cycle/day 20 yrs)	14,600	14,600	14,600	14,600
Expected Annual Availability	98%	98%	95%	95%

An important consideration of BESS is their round trip energy efficiency, which is the amount of AC energy that the system can deliver relative to the amount of AC energy injected into the system during the preceding charge. Losses experienced in the charge/discharge cycle include those from the PCS (inverters), heating and ventilation, control system losses, and auxiliary losses.

The Li-ion technology experiences degradation both in terms of capacity and round-trip efficiency with time, as influenced by a variety of factors including number of full charge/discharge cycles per day and environmental exposure. Typically, integrators employ augmentation strategies such as oversizing and/or periodic replacement, to ensure that the grid connected BESS is supplying the necessary MW, MWh, and expected cycle life during the performance period. To meet electric utility customer needs, BESS integrators are willing to provide a guaranteed equipment life of about 20 years with an appropriate augmentation strategy. Each battery OEM and integrator strategy can be different and there are no set industry standards.

Vanadium redox flow batteries, on the other hand, do not experience significant performance degradation due to the fact that the charged electrons are stored in the liquid (vanadium) form that has limited self-discharge characteristics and it also exhibits almost no degradation when the system is left discharged for long periods of time. However, given the large volume of solution that must be pumped, the auxiliary load and recharge time of a similarly sized flow battery system is higher when compared to the Li-ion technology.

9.3.2. Plant Staffing

Staffing for a 25 MW BESS installation (regardless of storage duration) generally assumes the utilization of a remote monitoring/operating system. No additional staffing requirements are included for the BESS options.

9.4. Conceptual Capital Cost Estimates

The capital cost for an installed BESS includes the costs of the energy storage equipment, power conversion equipment, power control system, balance of system including site utilities, electric scope to the high side of the GSU transformer, and installation costs.

For Li-Ion systems, battery cells are arranged and connected into strings, modules, and packs which are then packaged into a DC system meeting the required power and energy specifications of the project. The DC system includes internal wiring, temperature and voltage monitoring equipment, and an associated battery management system responsible for managing low-level safety and performance of the DC battery system. For vanadium redox flow batteries, the DC system costs include electrolyte storage tanks, membrane power stacks, and container costs for the system along with associated cycling pumps and battery management controls. Each system would involve a PCS to convert the produced DC power to AC power for ultimate grid utilization.

Conceptual level capital cost estimates for 25 MW Li-ion and vanadium redox flow BESS are summarized in the table below[31].

Table 9.4-1. Conceptual BESS Capital Costs

Conceptual Capital Costs	Net Output	Major Equipment	BOP	Indirects	Subtotal - EPC	Owner's	AFUDC costs	Total Project Cost	Electric - Outside the Fence	Total with Interconnect
	MW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
25 MW Li-Ion (2 Hour)	25	$1,246	$64	$21	$1,331	$166	$53	$1,550	$380	$1,930
25 MW Li-Ion (4 Hour)	25	$2,256	$68	$23	$2,346	$240	$94	$2,680	$380	$3,059
25 MW Vanadium Flow (4 Hour)	25	$1,368	$94	$31	$1,493	$179	$60	$1,732	$380	$2,111
25 MW Vanadium Flow (6 Hour)	25	$1,925	$94	$31	$2,050	$246	$82	$2,378	$380	$2,758

AFUDC costs were estimated by PSE at 4% of project EPC cost and is included in the table above. The opinion of probable owner's costs represented above can roughly be broken down into the following general cost categories.

Table 9.4-2. General Owner's Cost Categories

Opinion of Probable Owner's Costs		BESS
Project Development/Management	%	1%
Execution Support	%	1%
Owner's Contingency	%	7%
Miscellaneous	%	2%
Total	%	11%

[31] BESS capital costs are presented on a $/kW basis in this report. In some cases, BESS capital costs are presented on a $/kWh basis, which is calculated by dividing the $/kW cost by the storage duration.

Table 9.4-3 provides assumptions and information related to outside the fence electrical infrastructure.

Table 9.4-3. Electrical Infrastructure Costs Outside the Fence

Plant Configuration	Nominal Installed Capacity (MW)	Radial Line /POI infrastructure	Cost ($ MM)			Cost ($/kW)
			Radial Line	POI infrastructure	Total	
BESS Li-Ion 2 /4 hrs	25	115 kV 5 mile line to POI. Breaker and one half interconnection arrangment at POI	$5.2	$4.3	$9.5	$379.6
BESS Vanadium Flow 4 /6 hrs	25	115 kV 5 mile line to POI. Breaker and one half interconnection arrangment at POI	$5.2	$4.3	$9.5	$379.6

9.5. Conceptual O&M Costs

The major component of the O&M cost for a Li-ion BESS system is related to energy and capacity augmentation. Augmentation maintains the BESS capability to serve the Owner’s requirement for the term of the agreement. These costs are typically covered in the fixed O&M costs. Additional fixed O&M costs typically include:

- 24x7 remote monitoring
- Remote troubleshooting
- Performing scheduled maintenance activities, inverter replacements, emergency and unscheduled maintenance support
- Periodic reporting, training and continuous improvement
- Software licensing and updates
- HVAC maintenance
- Auxiliary electrical loads
- Landscaping
- Mechanical/electrical inspections and updates

For flow battery systems, maintenance services typically include:

- Power stack and pump inspection and replacement
- Inverter replacements
- Sensor calibration
- Cooling systems service
- Tightening of plumbing fixtures, tightening of mechanical and electrical connections
- Periodic chemistry refresh and full discharge cycles to refresh capacity

At current, the equipment suppliers are providing fixed O&M services directly.

For both technologies, the total annual augmentation agreement is estimated based on the two full cycles/day discharge rate. No additional staffing costs are included as it is assumed that the BESS will be completely unmanned.

Per market sources for Li-Ion and Vanadium Redox flow BESS, O&M costs are presented as fixed costs on a $/kW-yr basis and are assumed to include any variable costs. Conceptual BESS O&M costs are summarized in the table below.

Table 9.5-1. Conceptual BESS O&M Costs

Conceptual O&M Costs	Fixed O&M	Variable O&M
	$/kW-yr	$/MWH
25 MW Li-Ion (2 Hour)	$20.54	$0.00
25 MW Li-Ion (4 Hour)	$32.16	$0.00
25 MW Flow (4 Hour)	$30.80	$0.00
25 MW Flow (6 Hour)	$40.27	$0.00

The O&M costs does not include electricity purchased to charge the batteries.

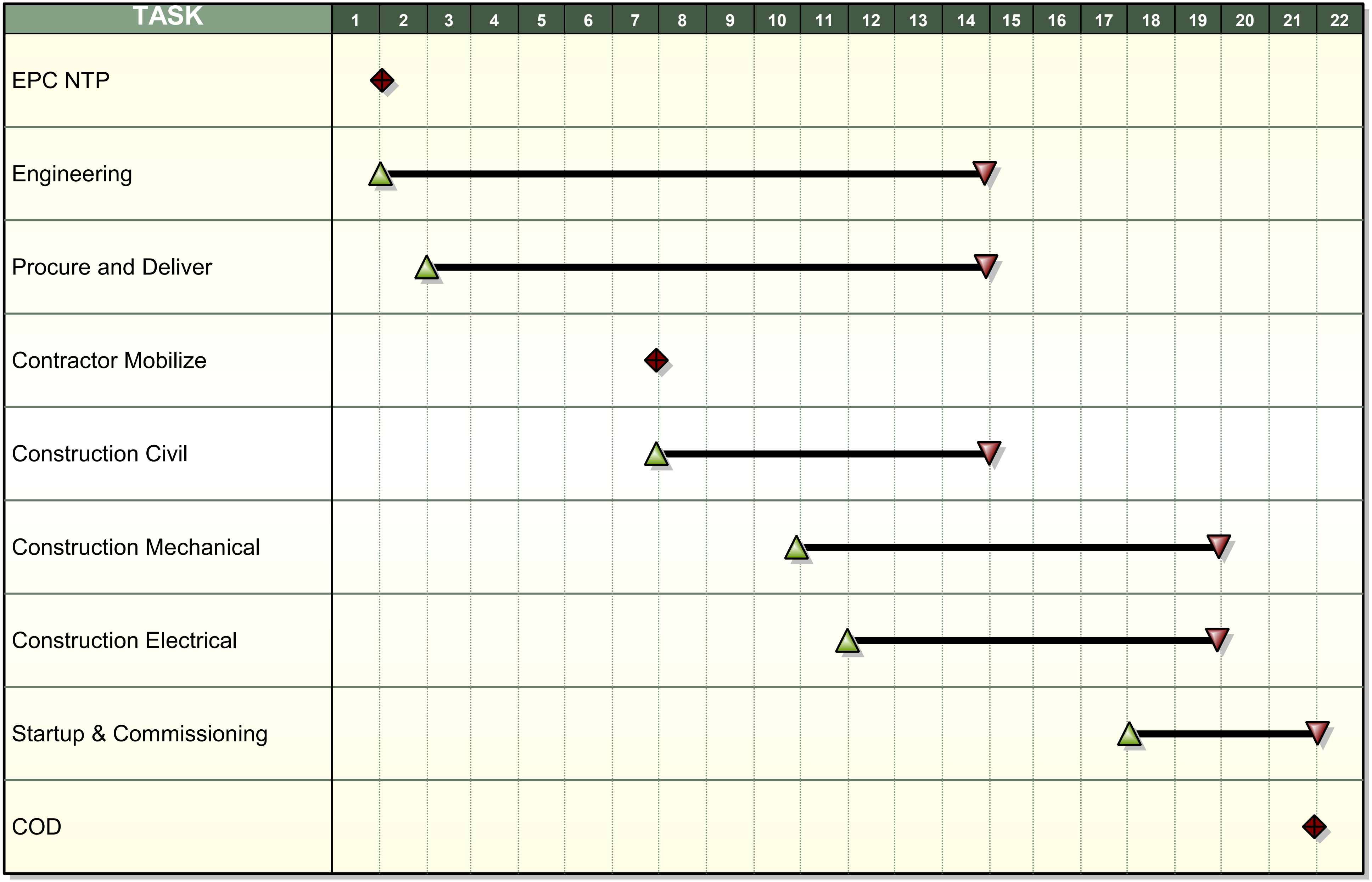
9.6. Project Implementation Schedule

The BESS integrator's scope of supply typically includes most of the systems up to the inverter terminal where AC power is available to the GSU transformer. Accordingly, the BESS integrator can deliver the major systems within approximately 9 months from NTP. Additional site engineering, foundation and substructure work, site utilities, and utility interconnection work is generally completed by a general/EPC contractor. A typical 25 MW BESS project can be commissioned and in commercial operation within 12 months from contractor NTP. A project implementation schedule is included in Appendix A and a representative capital spend curve is included in Appendix B.

Appendix A – Conceptual Project Implementation Schedules

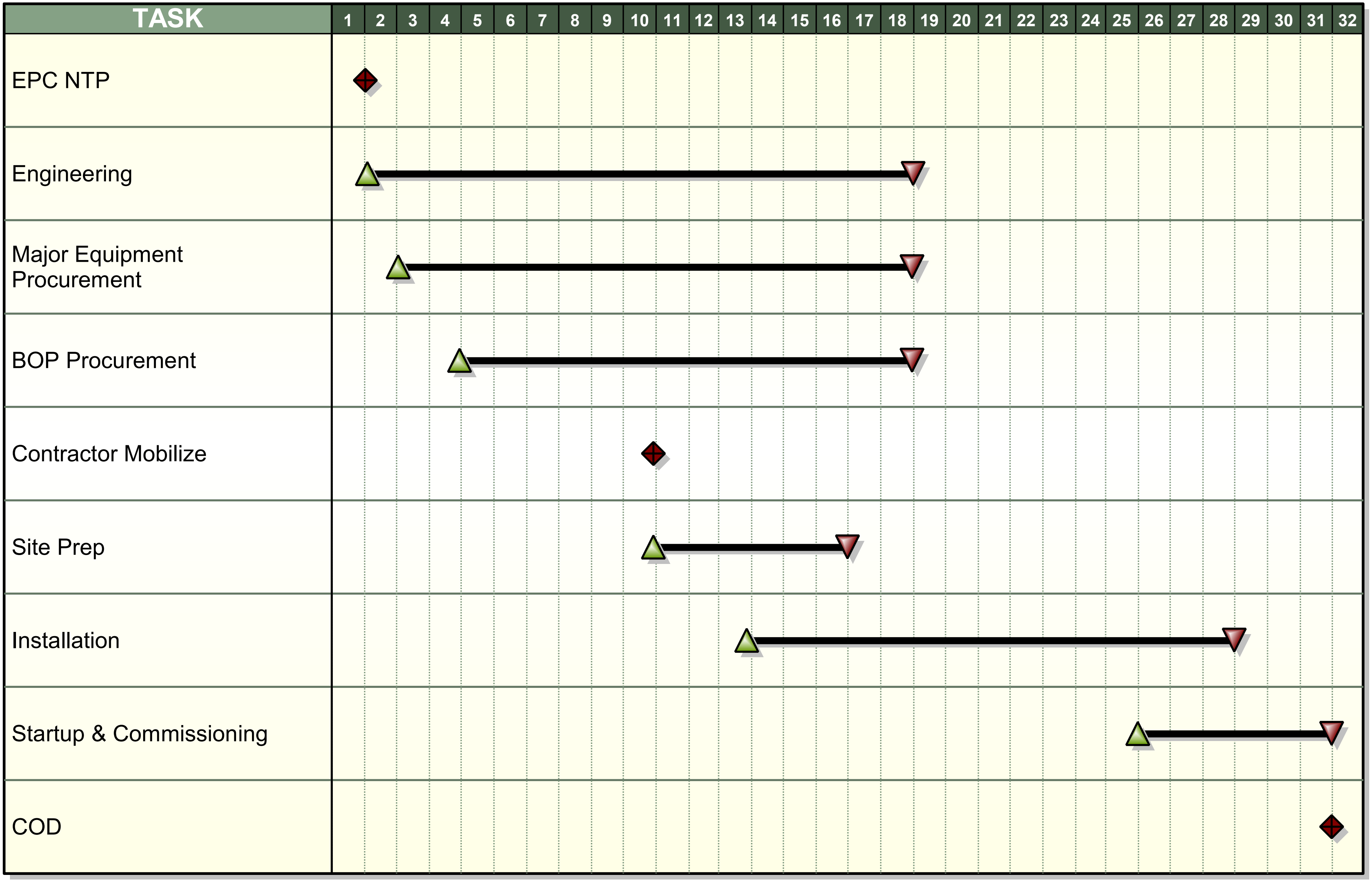
Puget Sound Energy
2019 Integrated Resource Plan
1x0 F-Class Conceptual Schedule

5/25/2018



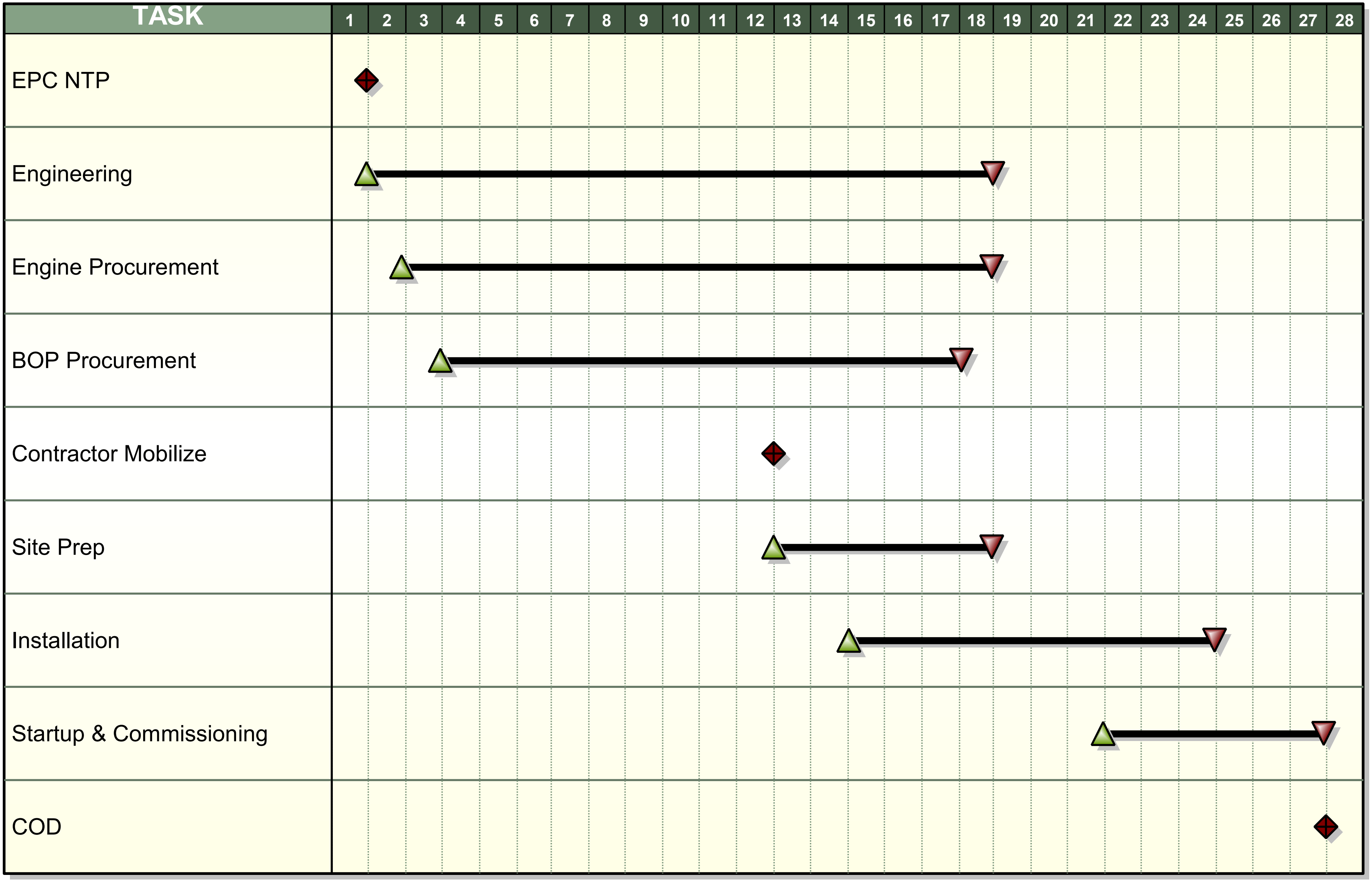
Puget Sound Energy
2019 Integrated Resource Plan
1x1 F-Class Conceptual Schedule

5/25/2018



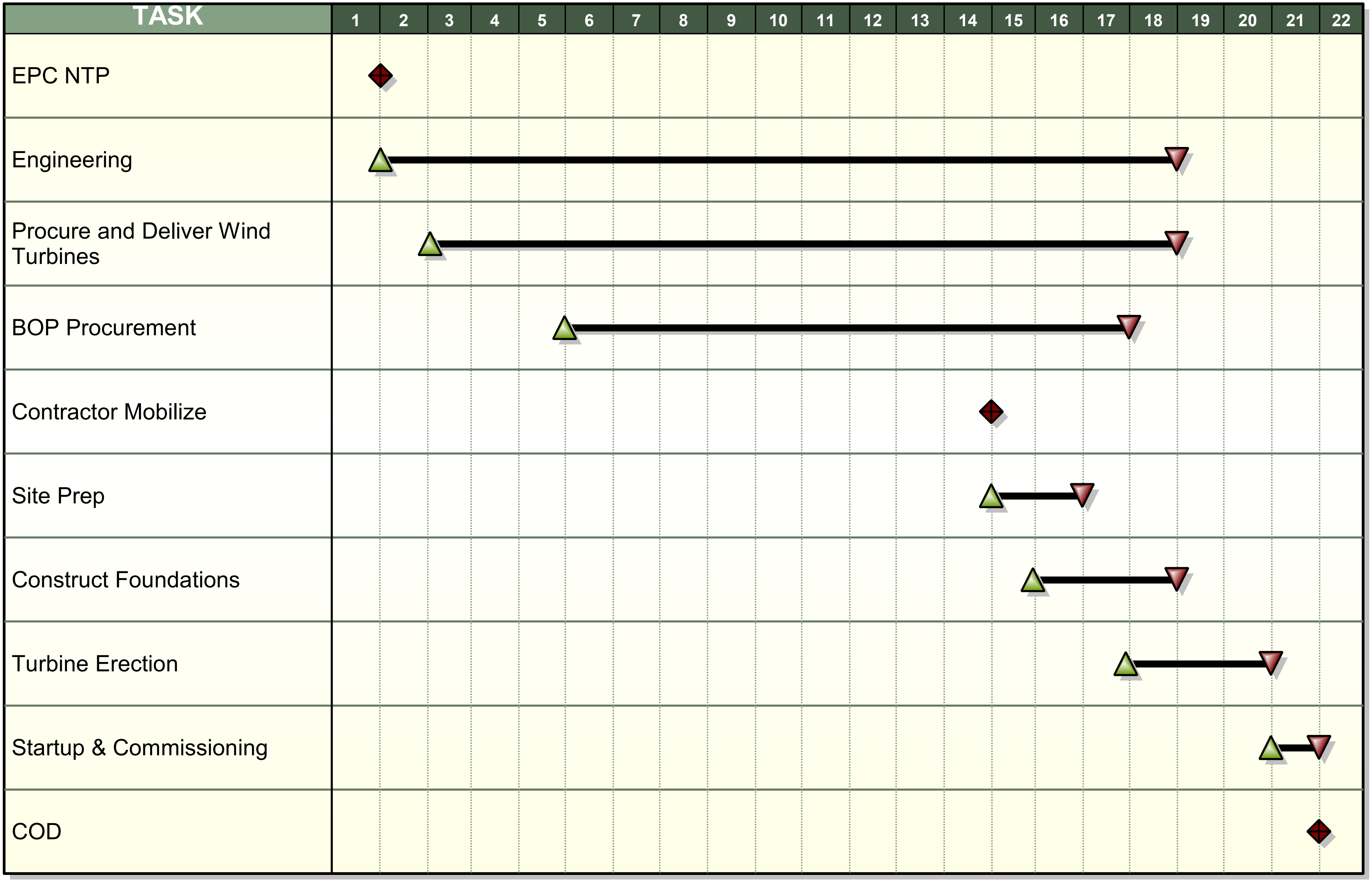
Puget Sound Energy
2019 Integrated Resource Plan
12x0 Reciprocating Engine Conceptual Schedule

5/25/2018



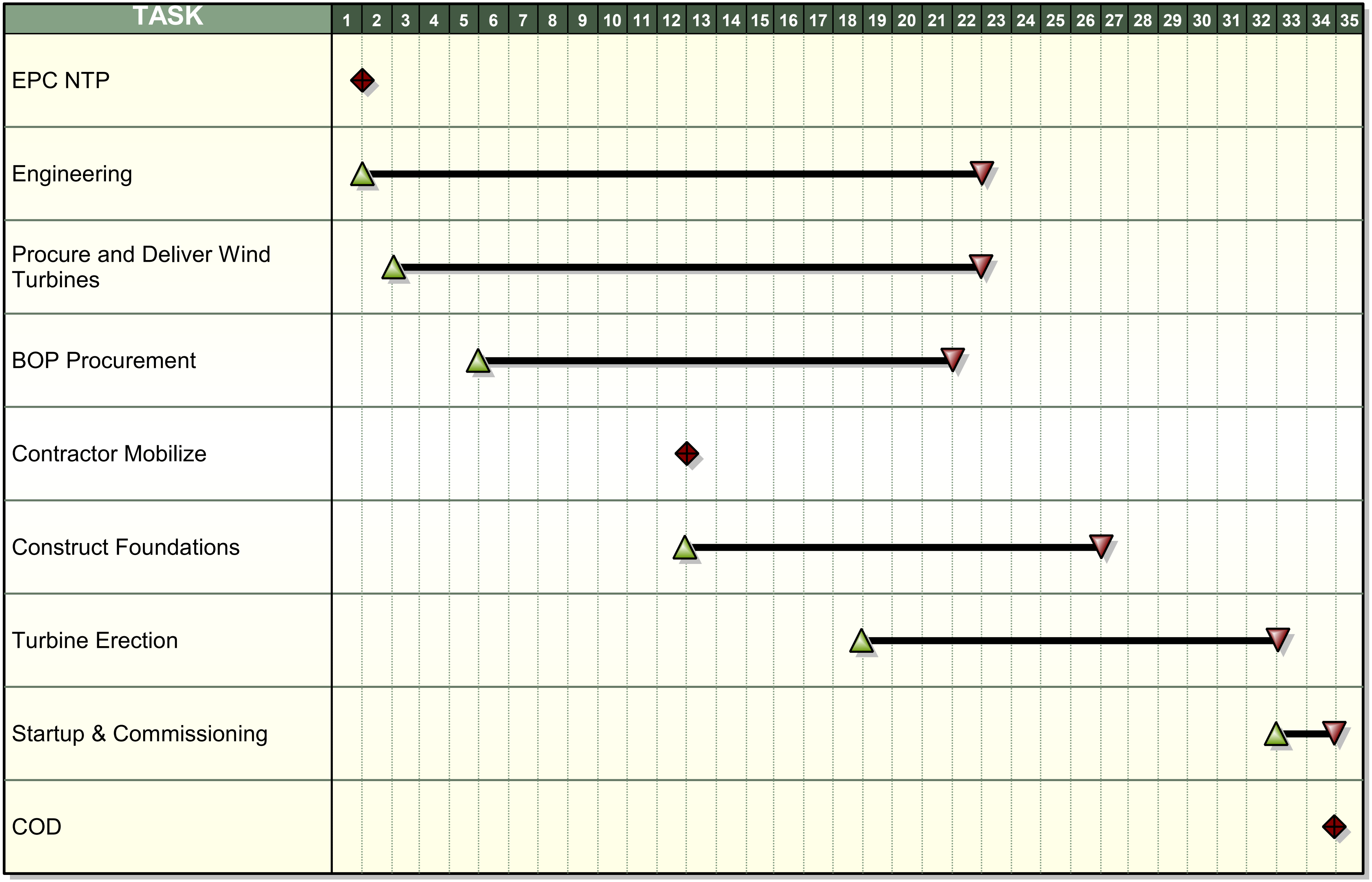
Puget Sound Energy
2019 Integrated Resource Plan
Wind Farm Conceptual Schedule

5/25/2018



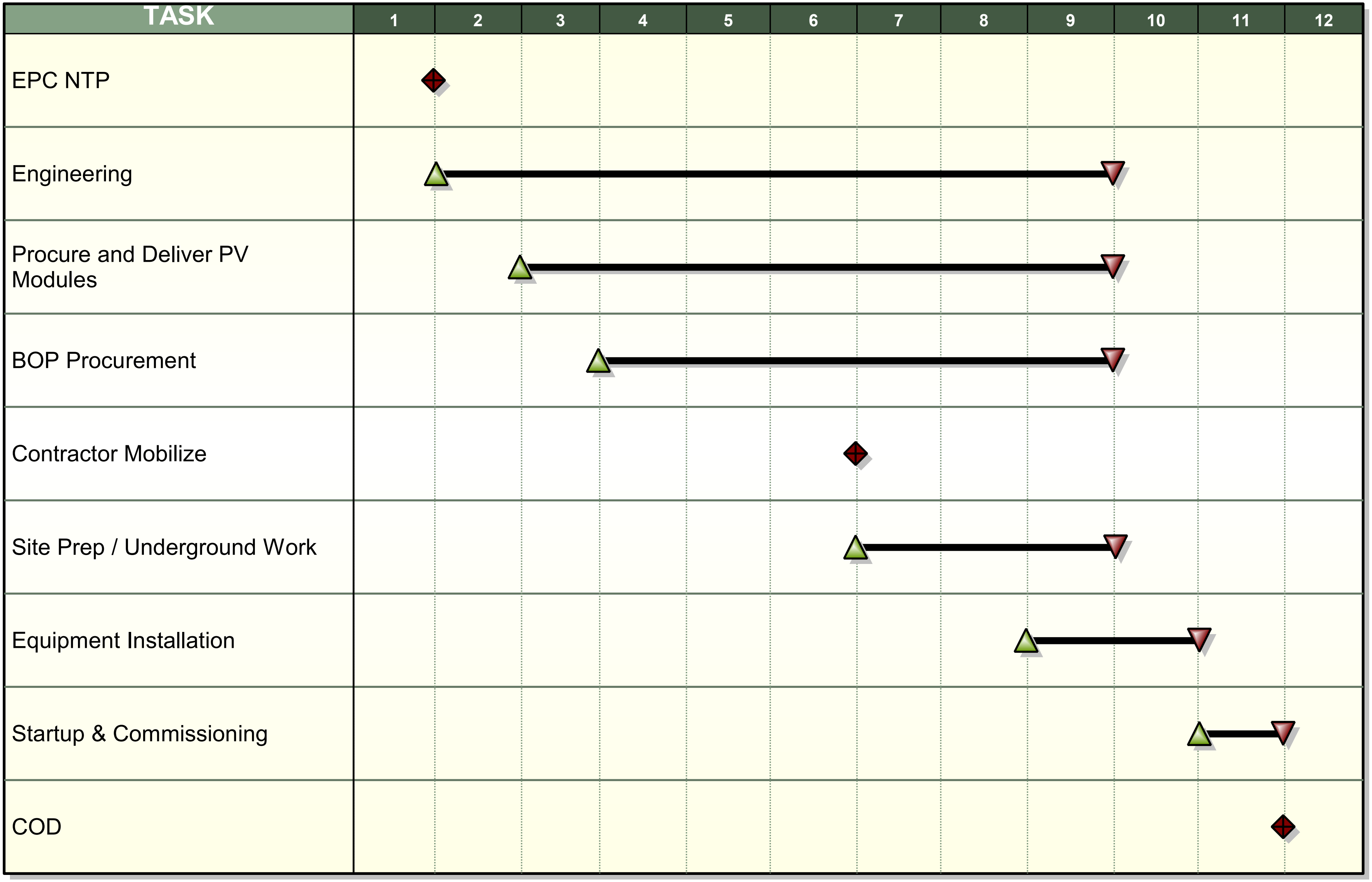
Puget Sound Energy
2019 Integrated Resource Plan
300 MW Off Shore Wind Farm Conceptual Schedule

5/25/2018



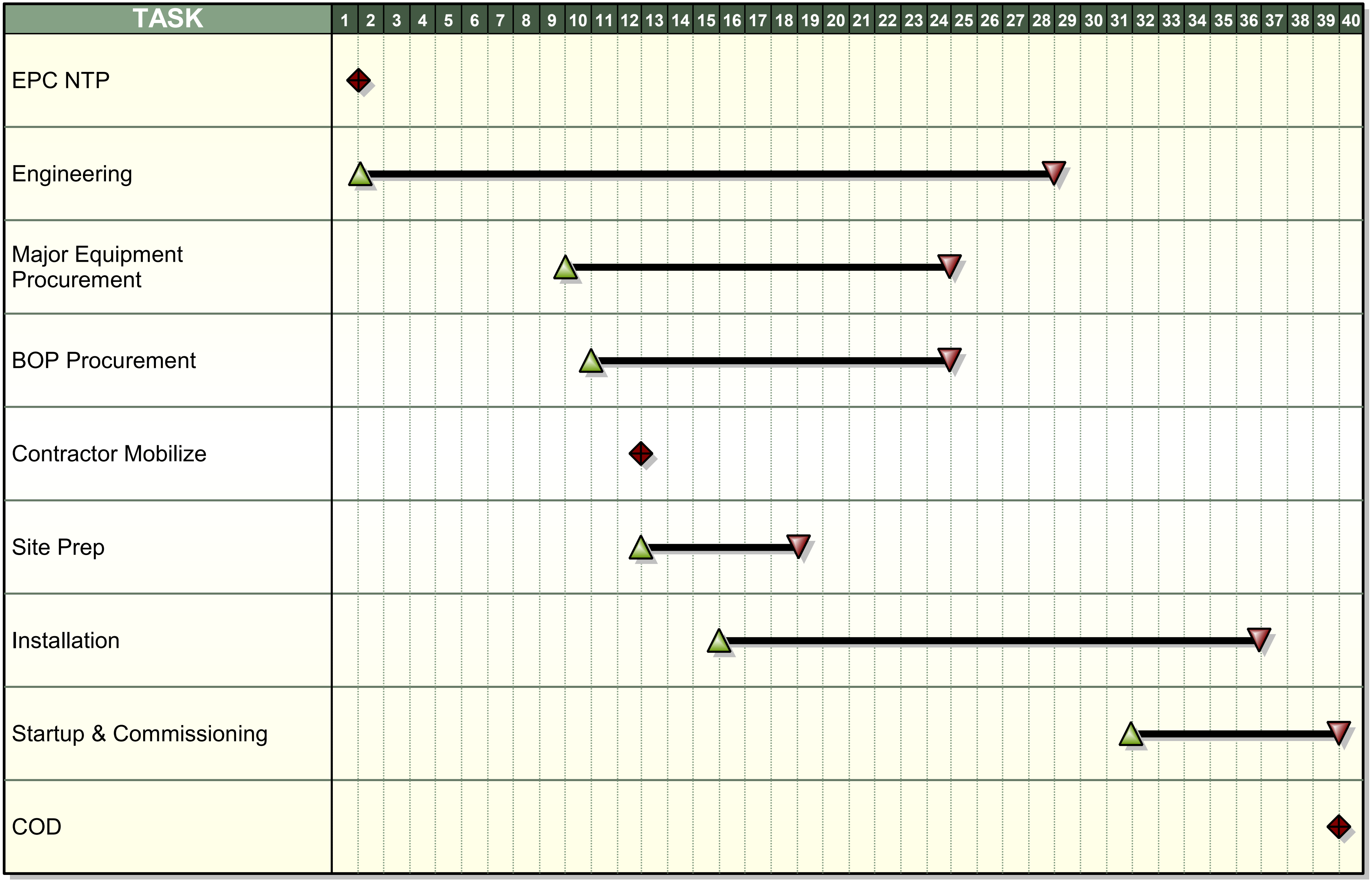
Puget Sound Energy
2019 Integrated Resource Plan
PV Solar Conceptual Schedule

5/25/2018



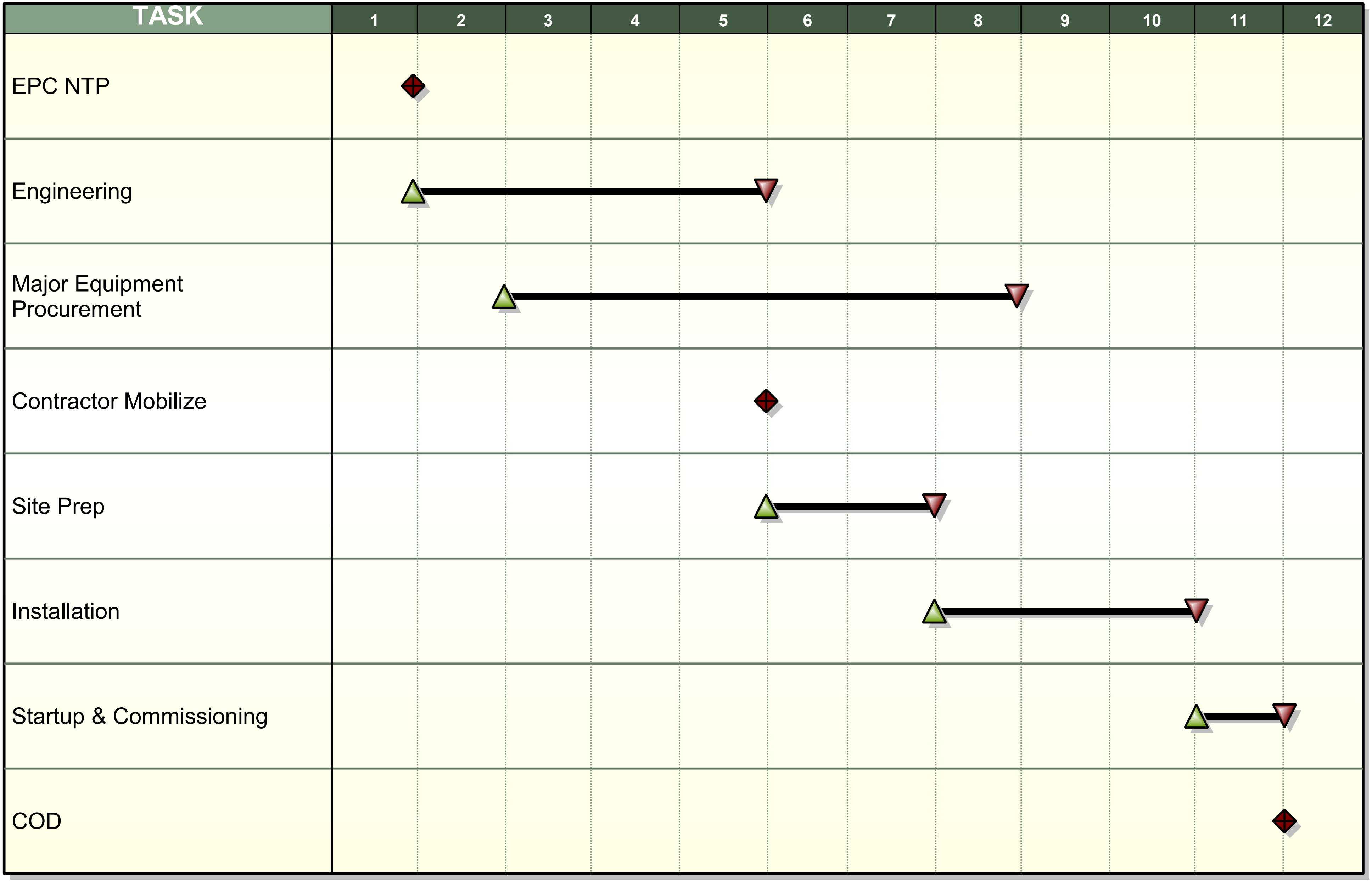
Puget Sound Energy
2019 Integrated Resource Plan
15 MW Biomass Plant Conceptual Schedule

5/25/2018

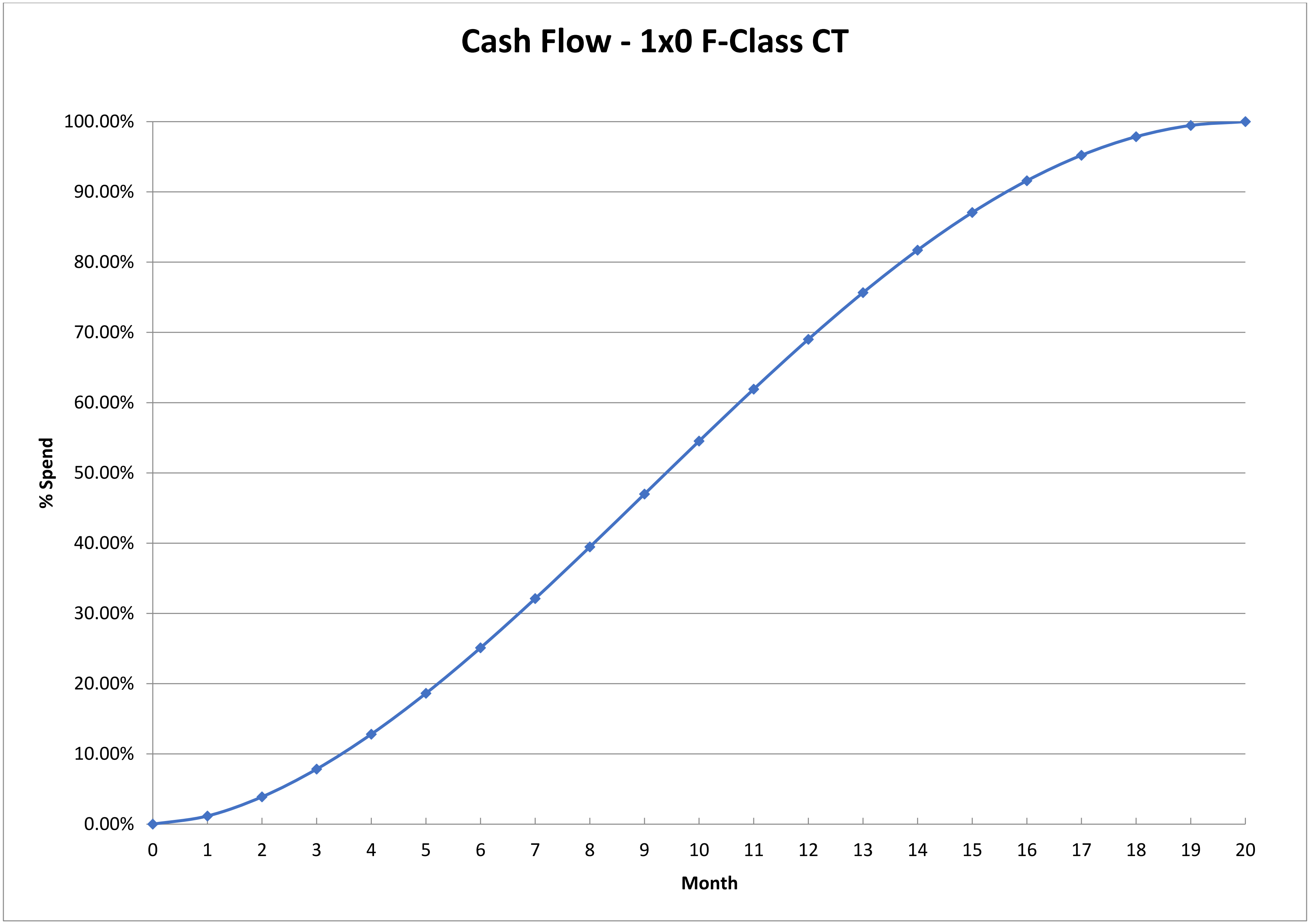


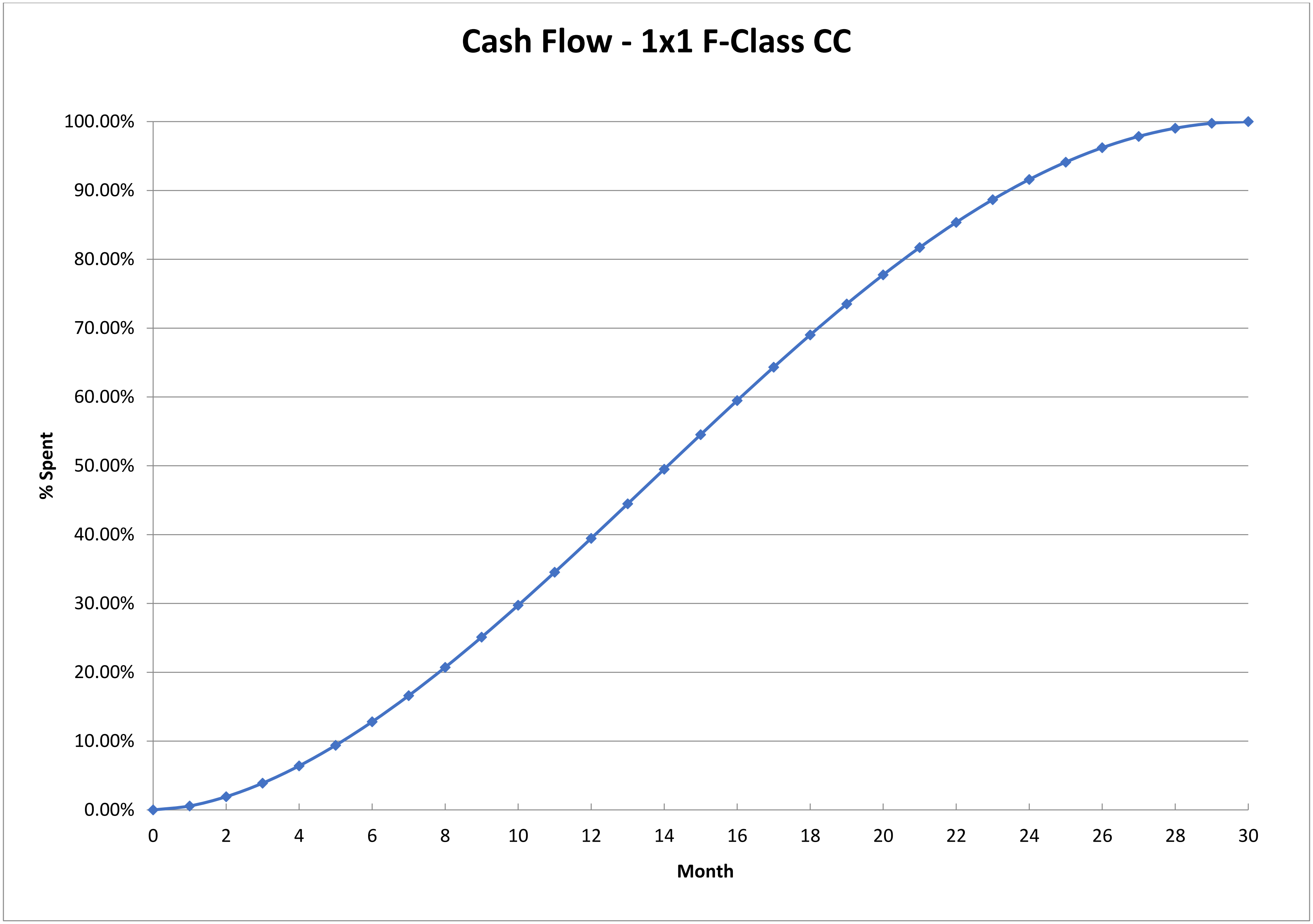
Puget Sound Energy
2019 Integrated Resource Plan
Battery Plant

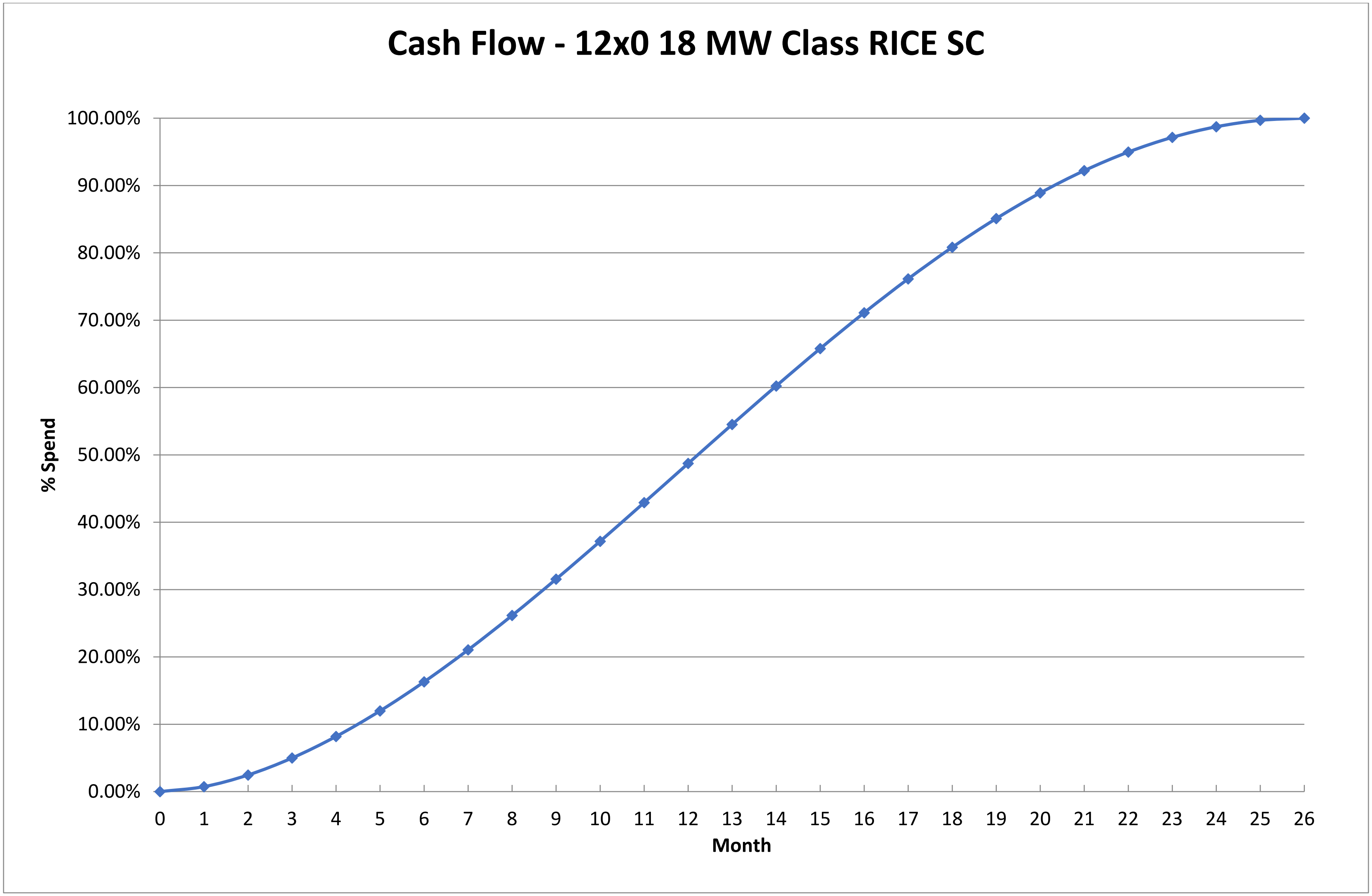
5/25/2018

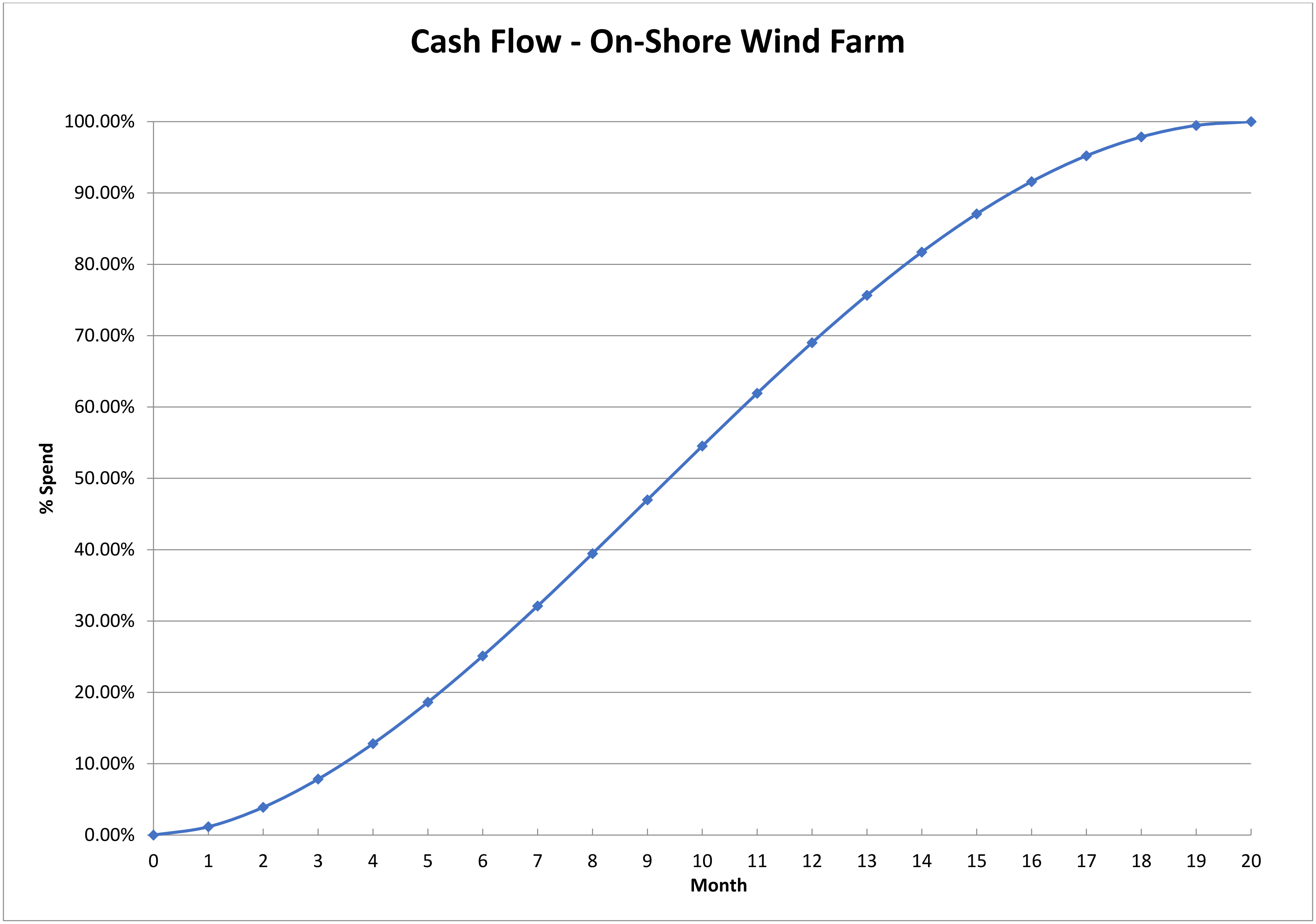


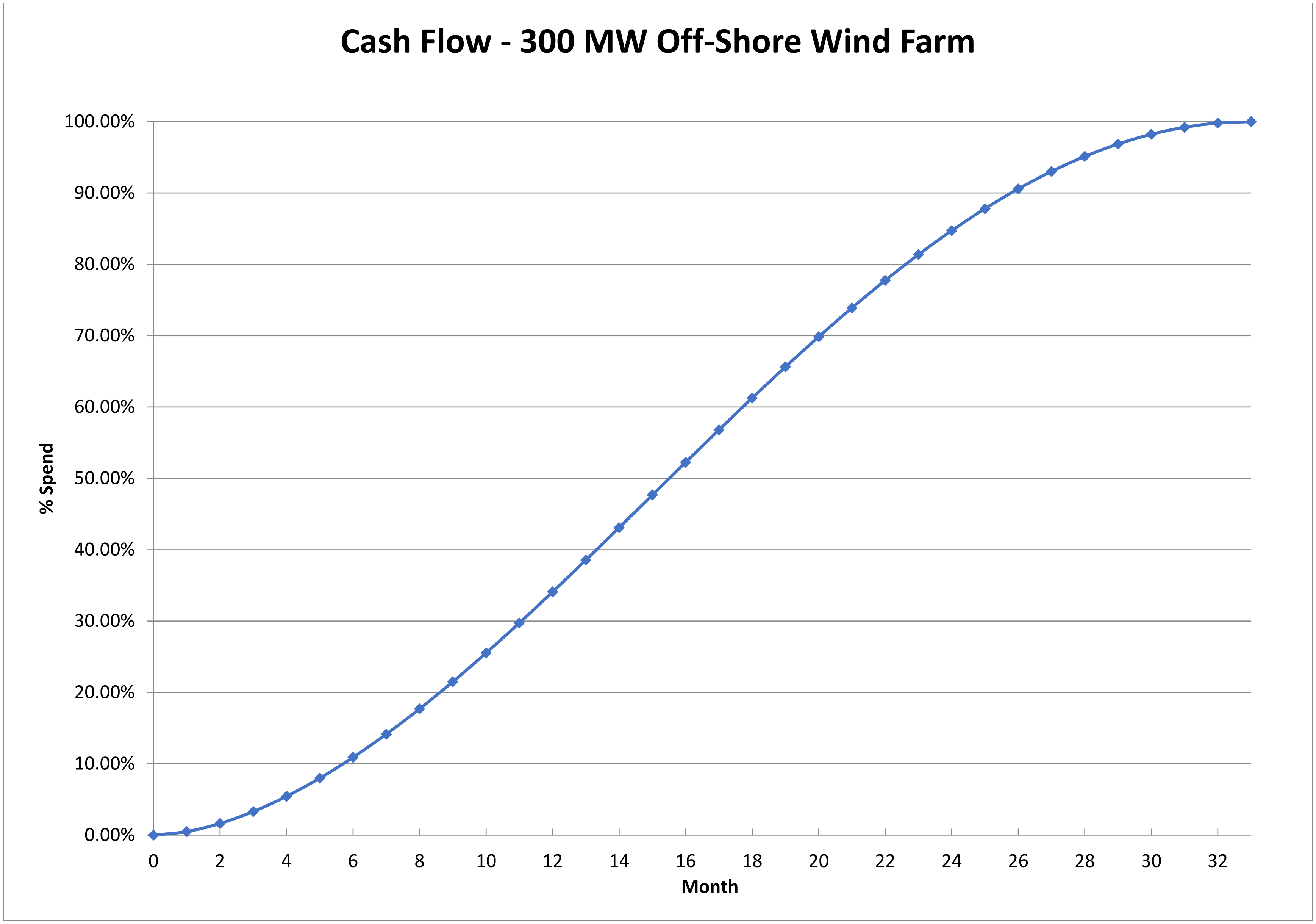
Appendix B – Conceptual Capital Spend Curves

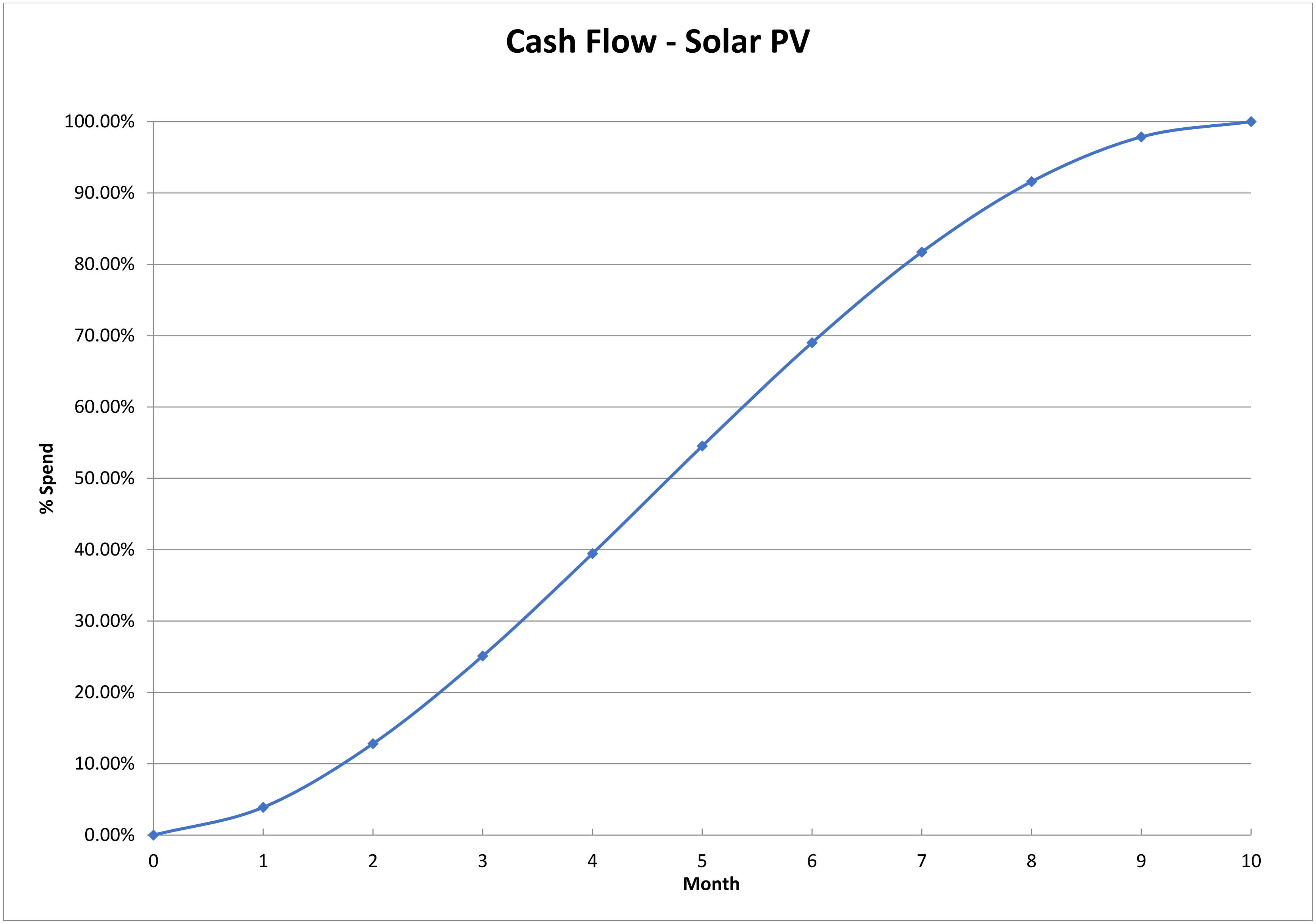

Cash Flow - 1x0 F-Class CT
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
% Spend
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Month

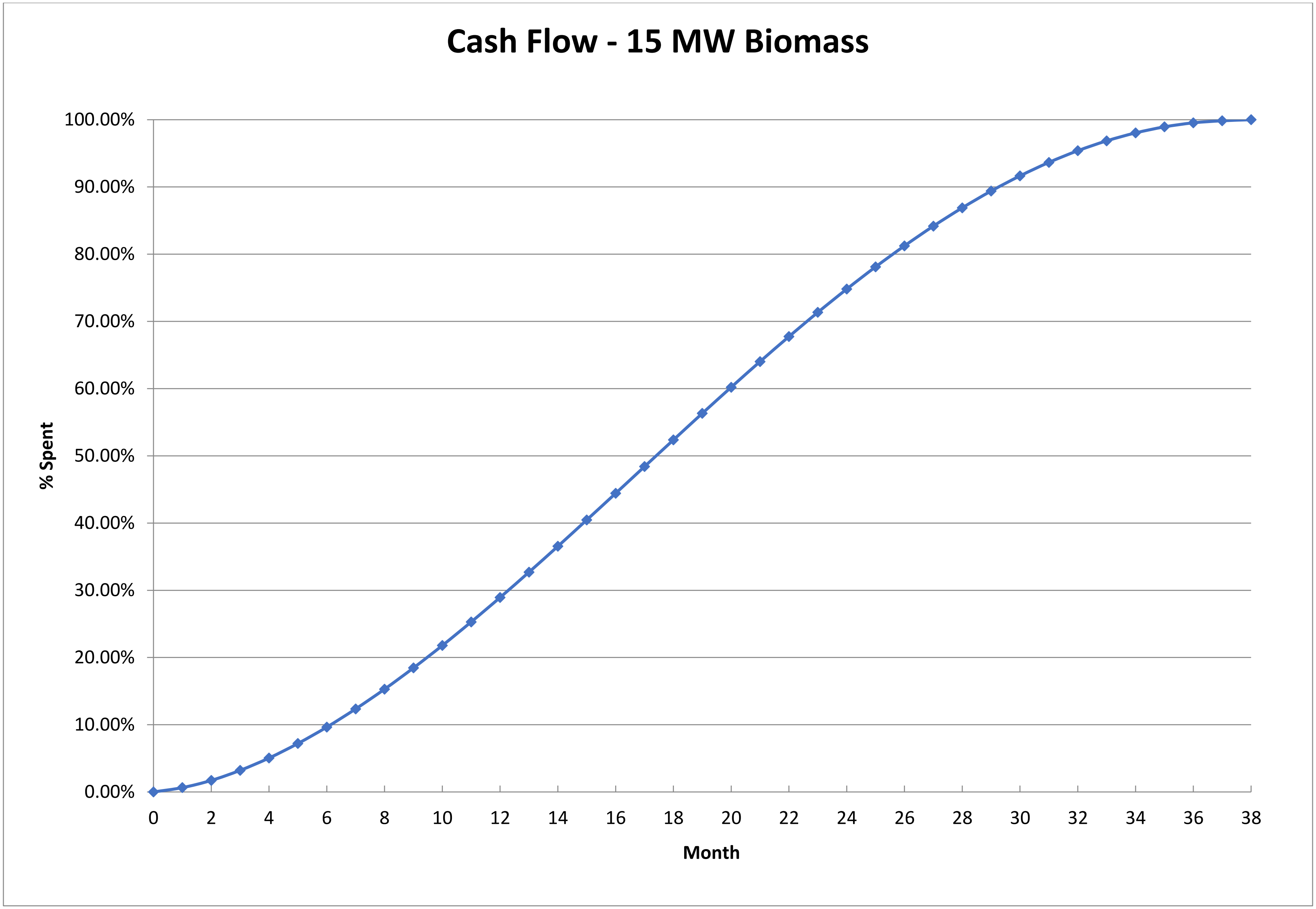

Cash Flow - 1x1 F-Class CC
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
% Spent
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
Month

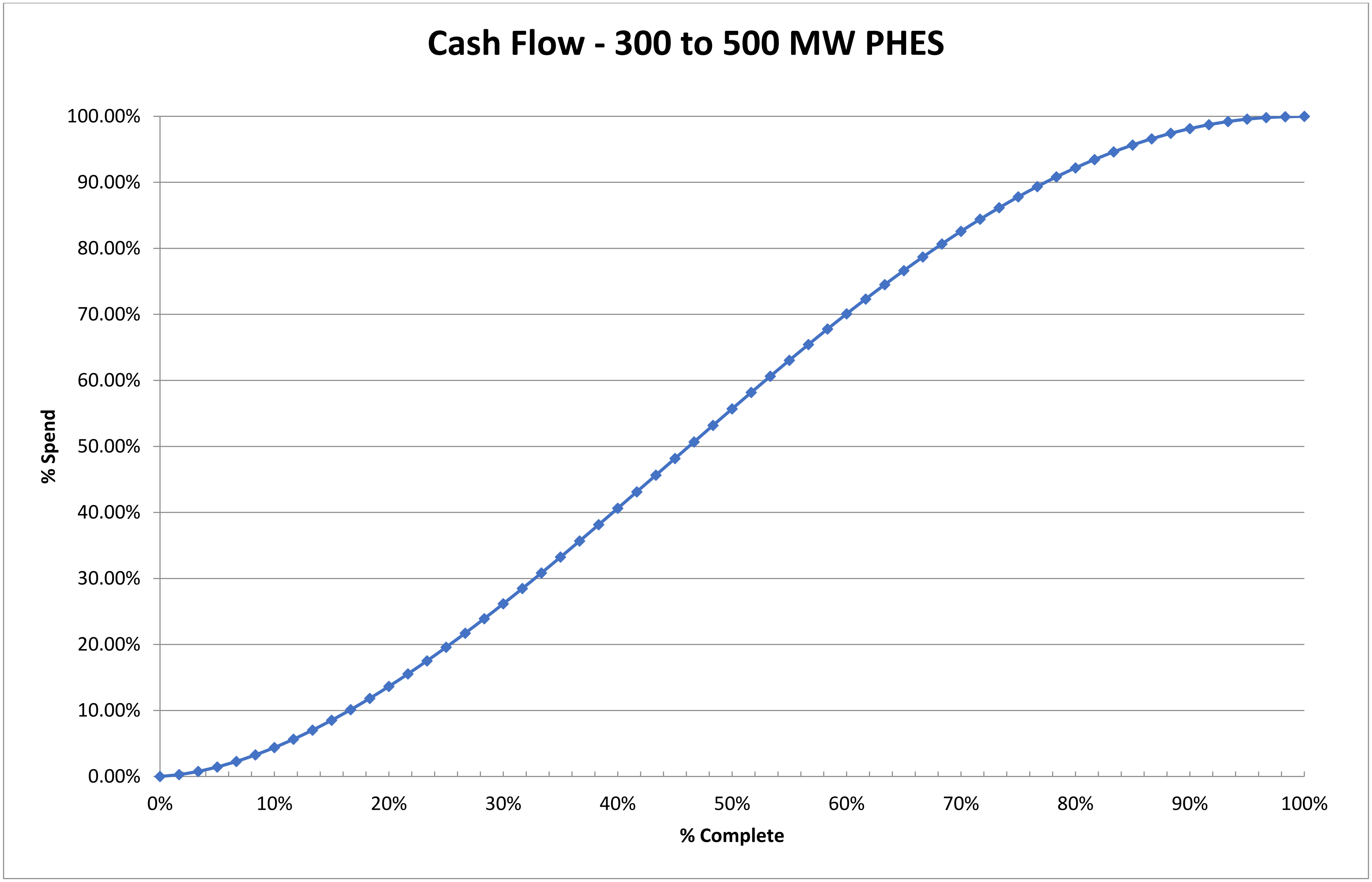

Cash Flow - 12x0 18 MW Class RICE SC
% Spend
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26
Month

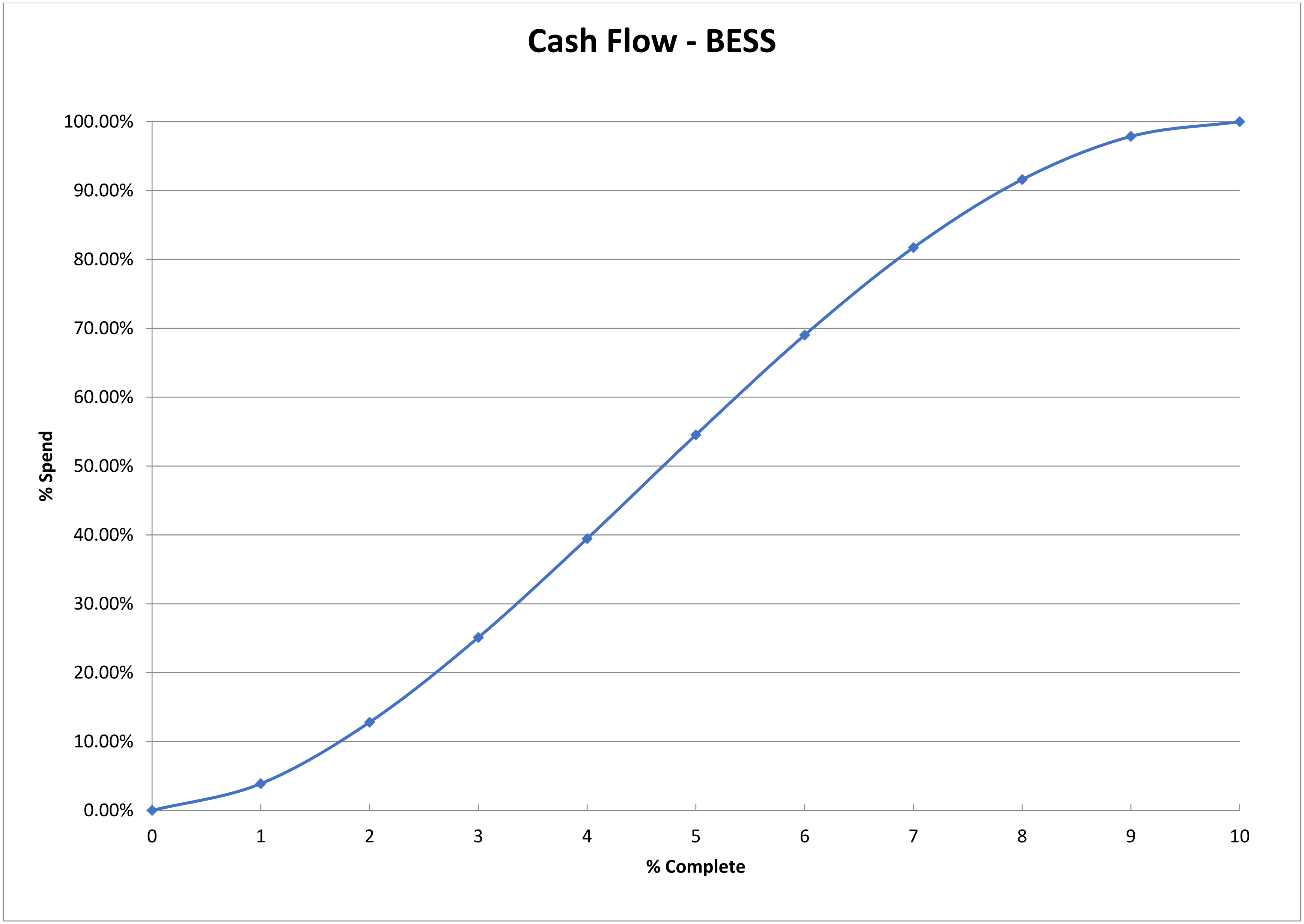

Cash Flow - On-Shore Wind Farm
% Spend
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
Month


Cash Flow - 300 MW Off-Shore Wind Farm
% Spend
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32
Month


Cash Flow - Solar PV
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
% Spend
0 1 2 3 4 5 6 7 8 9 10
Month


Cash Flow - 15 MW Biomass
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
% Spent
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
32
34
36
38
Month


Cash Flow - 300 to 500 MW PHES
% Spend
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% Complete


Cash Flow - BESS
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
% Spend
0
1
2
3
4
5
6
7
8
9
10
% Complete

Appendix C – Modeling Inputs Summary Tables

2019 IRP Electric Supply-Side Resources - Thermal

2018 $	Units	1x0 F-Class Dual Fuel CT (NG)	1x0 F-Class Dual Fuel CT (FO)	1x1 F-Class CC (NG Only)	12x0 18 MW Class RICE (NG Only)	12x0 18 MW Dual Fuel RICE (NG)	12x0 18 MW Dual Fuel RICE (FO)
ISO Capacity Primary	MW	225	217	336	219	201	173
Winter Capacity Primary (23 degrees F)	MW	237	229	348	219	201	173
Incremental Capacity DF (23 degrees F)	MW			19			
Capital Cost + Duct Fire*	$/KW	$825		$1,167	$1,192	$1,357	
O&M Fixed	$/KW-yr	$3.93		$13.44	$3.74	$4.12	
Flexibility	$/KW-yr						
O&M Variable	$/MWh	$0.69		$2.45	$5.30	$5.80	
Start Up Costs	$/Start	$6,502					
Capacity Credit	%						
Operating Reserves	%						
Forced Outage Rate		2.38%	2.38%	3.88%	3.30%	3.30%	3.30%
ISO Heat Rate – Baseload (HHV)	Btu/KWh	9,904	10,056	6,624	8,445	8,582	8,780
ISO Heat Rate – Turndown (HHV)	Btu/KWh	15,794	12,856	7,988	11,288	11,471	11,736
Heat Rate – DF	Btu/KWh			8,867			
Min Capacity	%	30%	50%	38%	30%	30%	30%
Start Time (hot)	minutes	21	21	45	5	5	5
Start Time (warm)	minutes	21	21	60	5	5	5
Start Time (cold)	minutes	21	21	150	5	5	5
Start up fuel (hot)	mmBtu	366	338	839	69	69	57
Start up fuel (warm)	mmBtu	366	338	1,119	69	69	57
Start up fuel (cold)	mmBtu	366	338	2,797	69	69	57
Ramp Rate (a)	MW/min	40	40	40	16	16	16
Location							
Fixed Gas Transport	$/Dth/Day						
Fixed Gas Transport	$/KW-yr						
Variable Gas Transport	$/MMBtu						
Fixed Transmission	$/KW-yr						
Variable Transmission	$/MWh						
Emissions:							
CO_2 - Natural Gas	lbs/MMBtu	118		118	118	122	
CO_2 - Distillate Fuel Oil	lbs/MMBtu		160				160
NOx - Natural Gas	lbs/MMBtu	0.004		0.008	0.029	0.037	
NOx - Distillate Fuel Oil	lbs/MMBtu		0.014				0.130
First Year Available							
Economic Life	Years	30	30	30	30	30	30
Greenfield Dev. & Const. Lead-time	years	1.8	1.8	2.7	2.3	2.3	2.3

2019 IRP Electric Supply-Side Resources - Renewables

2018 $	Units	On-Shore Wind - MT (Site #1)	On-Shore Wind - MT (Site #2)	On-Shore Wind - MT (Site #3)	On-Shore Wind - WA (Site #4)	On-Shore Wind - MT (Site #1)	On-Shore Wind - MT (Site #2)	On-Shore Wind - MT (Site #3)	On-Shore Wind - WA (Site #4)	Offshore Wind - WA Coast	Solar PV - WA	Solar PV - WA	Biomass
ISO Capacity Primary	MW	100	100	100	100	300	300	300	300	300	25	100	15
Capacity Credit	%												
Operating Reserves	%												
Capacity Factor	%	35.5%	42.4%	45.8%	31.9%	35.5%	42.4%	45.8%	31.9%	35.3%	24.2%	24.2%	85%
Capital Cost	$/KW	$1,722	$2,212	$1,722	$1,749	$1,617	$1,802	$1,617	$1,633	$6,547	$1,922	$1,614	$9,695
O&M Fixed	$/KW-yr	$37.00	$37.00	$37.00	$37.00	$37.00	$37.00	$37.00	$37.00	$120.00	$27.19	$21.90	$345.20
O&M Variable	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.60
Land Area	acres/MW	48.2	48.2	48.2	48.2	48.2	48.2	48.2	48.2		5 - 7	5 - 7	6 - 8
Degradation	%/year	0	0	0	0	0	0	0	0	0	0.50%	0.50%	N/A
Location	-												
Fixed Transmission	$/KW-yr												
Variable Transmission	$/MWh												
Loss Factor to PSE	%												
Heat Rate – Baseload (HHV)	Btu/KWh												14,599
Emissions:													
NO_x	lbs/MMBtu												0.03
SO_2	lbs/MMBtu												0.03
CO_2	lbs/MMBtu												213
First Year Available													
Economic Life	Years	25	25	25	25	25	25	25	25	25	20	20	30
Greenfield Dev. & Const. Leadtime	years	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	3.2	1.0	1.0	3.3

2019 IRP Electric Supply-Side Resources - Energy Storage

2018 $	Units	PHES - Closed Loop (8 Hour)	PHES Closed Loop (8 Hour)	BESS - 25 MW Li-Ion (2 Hour / 2 Cycles Daily)	BESS - 25 MW Li-Ion (4 Hour / 2 Cycles Daily)	BESS - 25 MW Flow (4 Hours / 2 Cycles Daily)	BESS - 25 MW Flow (6 Hours / 2 Cycles Daily)
Nameplate Capacity	MW	500	300	25	25	25	25
Capacity Credit	%						
Operating Reserves	%						
Capital Cost (f)	$/KW	$2,661	$2,679	$1,930	$3,059	$2,111	$2,758
O&M Fixed	$/KW-yr	$14.55	$17.40	$20.54	$32.16	$30.80	$40.27
O&M Variable	$/MWh	$0.90	$1.50	$0.00	$0.00	$0.00	$0.00
Forced Outage Rate	%	1%	1%	<2%	<2%	<5%	<5%
Degradation	%/year	(a)	(a)	(d)	(d)	(d)	(d)
Operating Range (e)	%	147-500 MW (b)	112.5-300 MW (c)	2% to 100%	2% to 100%	2% to 100%	2% to 100%
R/T Efficiency	%	80%	80%	82%	87%	73%	73%
Discharge at Nominal Power	Hours	8	8	2	4	4	6
Location							
Fixed Transmission	$/KW-yr						
Variable Transmission	$/MWh						
Flexibility Benefit	$/KW-yr						
First Year Available							
Economic Life	Years	30+	30+	20	20	20	20
Greenfield Dev. & Const. Leadtime	years	5 - 8	5 - 8	1	1	1	1

Notes

PHES (assumed to represent a slice of a larger project).

a - PHES degradation close to zero

b - The operating range minimum is the average of the minimum at max (111 MW) and min head (183 MW).

c - The operating range minimum is the average of the minimum at max (86 MW) and min head (139 MW).

Li-ion BESS: Additional capacity prepurchased included in capital to ensure 20 yr operating life

d - Fixed O&M costs include augmentation by OEM ensuring MW and MWh rating for project life.

e - Battery can discharge based on the range of nameplate % indicated.

Appendix D – Proxy Offshore Wind Submarine Cable Connections (PRELIMINARY)

Submarine Cable Connections

Proxy 300 MW Offshore Wind Farm

DRAFT

Washington State, US
June 26, 2018

Prepared by: Vincent Curci
Arun Murali

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3 Wind Farm and Turbine Configuration 2
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1 Introduction

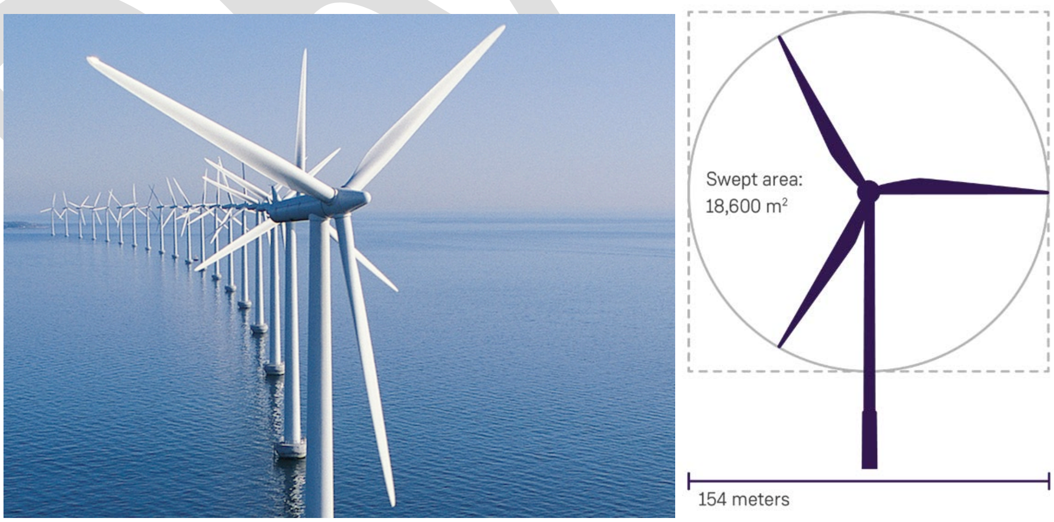
This summary report describes the cables and cable connections for a proxy 300 MW off-shore wind farm being considered by Puget Sound Energy in their 2019 integrated resource plan (IRP). The wind farm is assumed to be located approximately 3 miles from shore and, for the sake of this analysis, would consist of 50 turbines each rated at nominally 6 MW. The contents of this summary report are used to inform conceptual cost estimating considered as inputs to the 2019 IRP process. The contents of this summary-level report are considered preliminary in nature and based upon the best available information at the time of completion.

2 Proxy Wind Farm Characteristics

This analysis assumes the following nominal characteristics for the proxy off-shore wind farm under consideration. Figure 2-1 provides a general representation of nominal 6 MW class off-shore wind turbines.

- Rated capacity: 300 MW
- Turbine capacity: 6 MW (each)
- Number of turbines: 50
- Rotor diameter: 150 m (approximate)
- Hub height: 150 m (approximate)

Figure 2-1. Offshore 6 MW Wind Turbines and Diagram

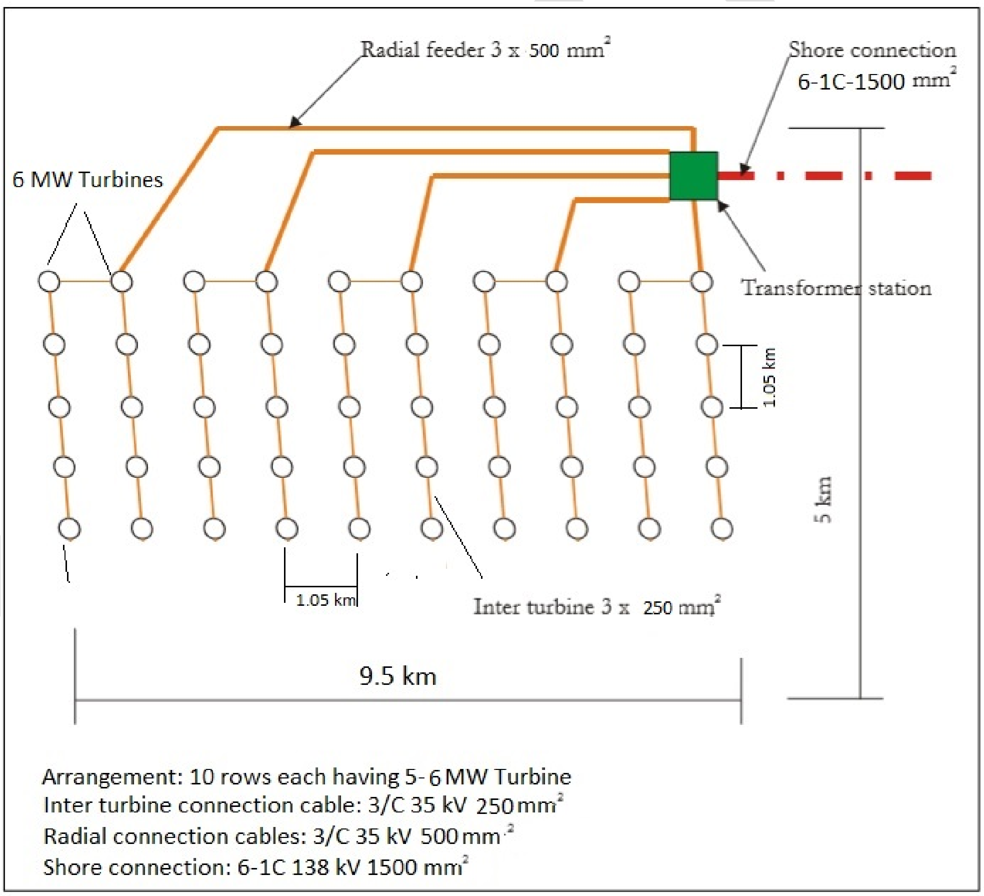


3 Wind Farm and Turbine Configuration

The proxy turbine configuration considered in this evaluation is described below and in Figure 3-1. The characteristics conveyed herein are representative in nature and not based on specific siting or project developments.

- Recommended spacing: 7 x rotor diameter per NREL
- Turbine spacing: 1,050 m = 1.05 km
- Array configuration: 10 rows x 5 turbines
- Spacing between rows: 1.05 km

Figure 3-1. Typical Arrangement of Turbines and Cable Connections



4 Inter Turbine Cables

Inter turbine cables connect to the turbines and deliver energy generated to the radial feeder cables as represented generally in Figure 3-1. The inter turbine cables would be as described below and in Figure 4-1.

- Inter turbine or infield cables: 3 conductor 35 kV armored
- Quantities per column: 4 x 1,050 = 4,200 m per column
- Number of rows: 10
- NREL factor for ocean bottom: 1.3
- Nominal Quantity: 54,600 m = 180,000 feet
- Conceptual Material Cost: $100 per foot material only
- Conceptual Installation Cost: $400 per foot

The NREL factor accounts for the depth and increases the calculated cable lengths by 30%

Figure 4-1. Inter Turbine Cable Characteristics (Representative)

Medium-voltage submarine cable, including fibre optic cable

Typical design of a medium-voltage submarine cable with a maximum voltage up to 36 kV, including fibre optic cable.

Type: 2XS(FL)2YRAA

1. Conductor: copper, circular stranded compacted
2. Conductor screening: extruded semi-conductive compound
3. Insulation: XLPE
4. Insulation screening: extruded semi-conductive compound
5. Screen: copper wires and copper helix, swelling powder
6. Laminated sheath: aluminium tape bonded to overlaying PE sheath
7. Fibre optic cable, optional
8. Fillers: polypropylene strings
9. Binder tapes
10. Bedding: polypropylene strings
11. Armour: galvanized round steel wires
12. Serving: bituminous compound, hessian tapes, polypropylene strings with coloured stripe

5 Radial Feeder Cables

The radial feeder cables connect the turbine interconnecting cables to the wind farm collector substation, which would be located on a platform at sea. The cables are assumed to have the general characteristics as described below and would employ similar construction methods to the cable shown in Figure 4-1 (but with a larger conductor).

- Inter turbine or infield cables: 3 conductor 35 kV armored
- NREL factor for ocean bottom: 1.3
- Nominal Quantity: 30,000 m = 99,000 feet
- Conceptual Material Cost: $150 per foot material only
- Conceptual Installation Cost $400 per foot

Since the wind farm configuration is representative, the location of the offshore substation is unknown at this time. As such, cable lengths have been approximated from the diagram in Figure 3-1.

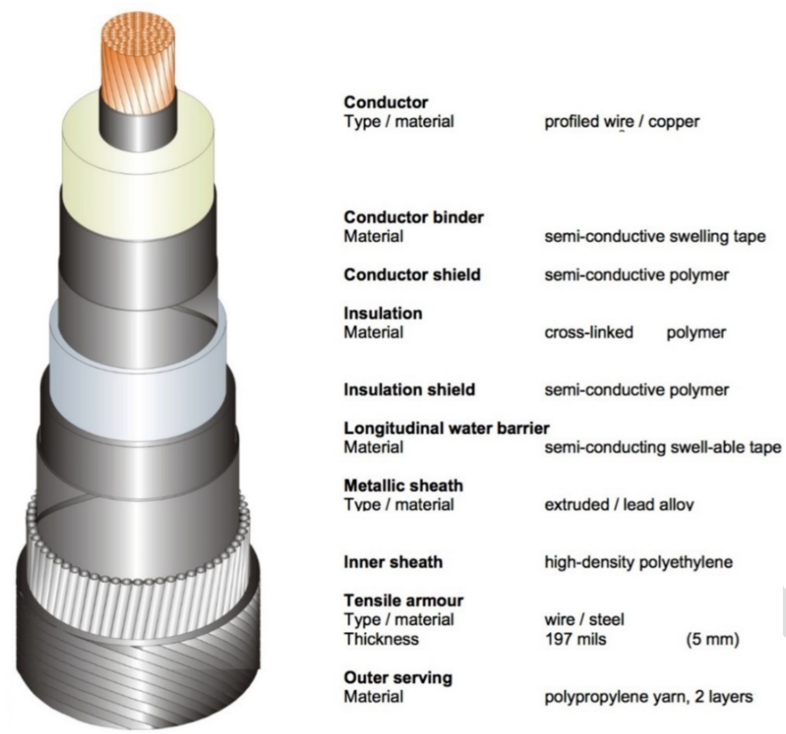
6 Export (or Shore) Connections

The export submarine cables would connect the offshore collector station to an onshore substation and would deliver energy generated from the wind farm. The cables assumed for this analysis are as described below and in Figure 6-1.

- Offshore or Export Cables: Single conductor (1C) 138 kV armored
- Distance from offshore sub: 3 miles – 4,828 m
- Number of circuits: 2
- Number of cables: 6
- NREL factor for ocean bottom: 1.3
- Nominal Quantity: 38,000 m = 125,000 feet
- Conceptual Material Cost:$280 per foot material only
- Conceptual Installation Cost: Varies: $700 per foot

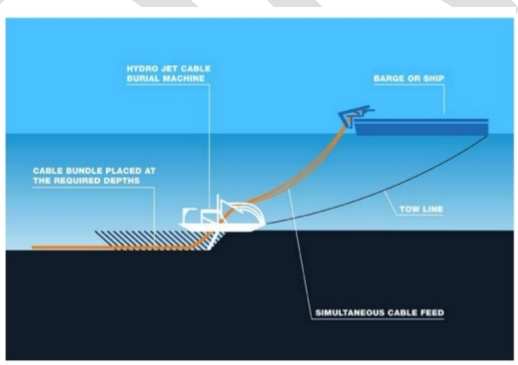
There are additional 138 kV cables needed from the shore landing to an inland substation. These additional cable lengths are not included in the total quantity listed above.

Figure 6-1. Representative Export (or Shore) Connection Submarine Cable



Typically, the cables would be laid from a cable laying ship or barge (Figure 6-2) and then buried below the ocean floor at a predetermined depth ranging from 4 to 10 feet using a jet plough.

Figure 6-2. Process of Laying and Burying Submarine Cables with a Plough



7 Onshore Land Cables

The onshore land cables would connect to the export submarine cables in a transition splice pit and continue to an onshore substation (Figure 7-1). The cables are assumed to be 138 kV cross-linked polyethylene insulated as shown in Figure 7-2. No quantities have been included in this report for onshore land cables.

Figure 7-1. Export Cable Connection to Land Cables

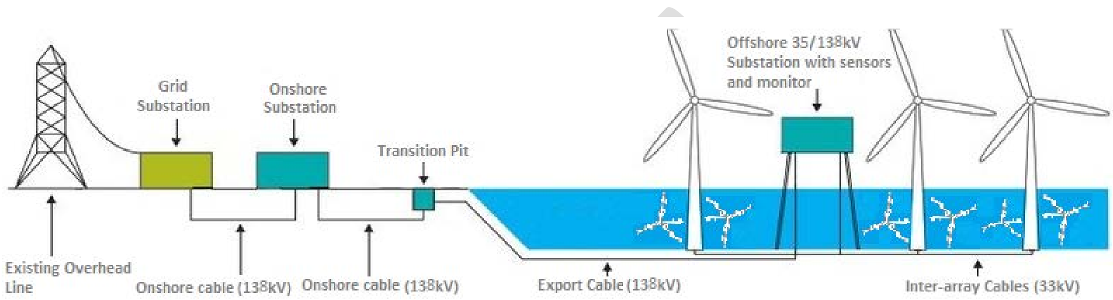


Figure 7-2. Representative Underground Land Cable

8 Estimated Cable Quantities and Costs

Table 8-1 summarizes the estimated cable quantities, material costs, and installation costs for a nominal 300 MW off-shore wind farm located approximately 3 miles of the coast of Washington State. The estimated quantities and values in the table below are conceptual in nature, based on the assumptions and approach outlined herein, based on feedback from suppliers, and based on publically available information. The estimated quantities and values are not based on an actual project development or detailed siting and cost estimating and are subject to change given the early stage development of off-shore wind in the United States.

Table 8-1. Estimated Quantities and Costs for Cables

Description	Length	Material Cost, $/ft	Total Material Cost, $	Installation Cost, $/ft	Total Installation Cost, $	Total Material and Installation Cost, $
Inter turbine cables	180,000	100	18,000,000	400	72,000,000	90,000,000
Radial Feeders	99,000	150	14,850,000	400	39,600,000	54,450,000
Export Cables (Offshore Substation to Shore)	125,000	280	35,000,000	700	87,500,000	122,500,000
Land Cables (Shore to Grid Substation)	Not included					
Total			***67,850,000***		***199,100,000***	***266,950,000***