APPENDIX H: GENERATING RESOURCES – BACKGROUND INFORMATION

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INTRODUCTION

This appendix describes the development of the planning assumptions for new generating and energy storage alternatives for use in the Seventh Power Plan.

GENERAL METHODOLOGY AND ASSUMPTIONS

As described in Chapter 13, the Council prioritized and categorized generating resources based on a resource's commercial availability, constructability, and quantity of developable potential in the Pacific Northwest during the 20-year power planning period. The three classifications used to analyze resources are:

- Primary: Significant resources that are deemed proven, commercially available, and deployable on a large scale in the Pacific Northwest at the start of the power planning period. These resources have the potential to play a major role in the future regional power system. Primary resources receive an in-depth, quantitative assessment to support system integration and risk analysis modeling. Primary resources are modeled in the Regional Portfolio Model (RPM).
- Secondary: Commercially available resources with limited, or small-scale, developmental potential in the Pacific Northwest. While secondary resources are currently in-service or available for development in the region, they generally have limited potential in terms of resource availability or typical plant size. Secondary resources receive at least a qualitative assessment to estimate status and potential and sometimes a quantitative assessment to estimate cost. While secondary resources are not explicitly modeled in the RPM, they are still considered viable resource options for future power planning needs.
- Long-term: Emerging resources and technologies that have a long-term potential in the Pacific Northwest but are not commercially available or deployable on a large scale at the beginning of the power planning period. Long-term resources receive a qualitative assessment and if available, quantification of key attributes.

Table H - 1 summarizes the generating resources by classification.

Table H - 1: Classification of Generating Resources*

Primary	Secondary	Long-term
Natural Gas Combined Cycle	Biogas Technologies (landfill, wastewater treatment, animal waste, etc.)	Engineered Geothermal
Natural Gas Simple Cycle (Aeroderivative Gas Turbine, Frame Gas Turbine)	Biomass – Woody Residues	Offshore Wind
Natural Gas Reciprocating Engine	Conventional Geothermal	Small Modular Nuclear Reactors (SMRs)
Onshore Wind	Hydropower (new)	Solar + Battery Storage
Solar Photovoltaic	Hydropower (upgrades to existing)	Storage Technologies**
	Storage Technologies**	Tidal Energy
	Waste Heat Recovery and Combined Heat and Power (CHP)	Wave Energy

* Resources are in alphabetical order
** Energy storage comprises many technologies at various stages of development and availability

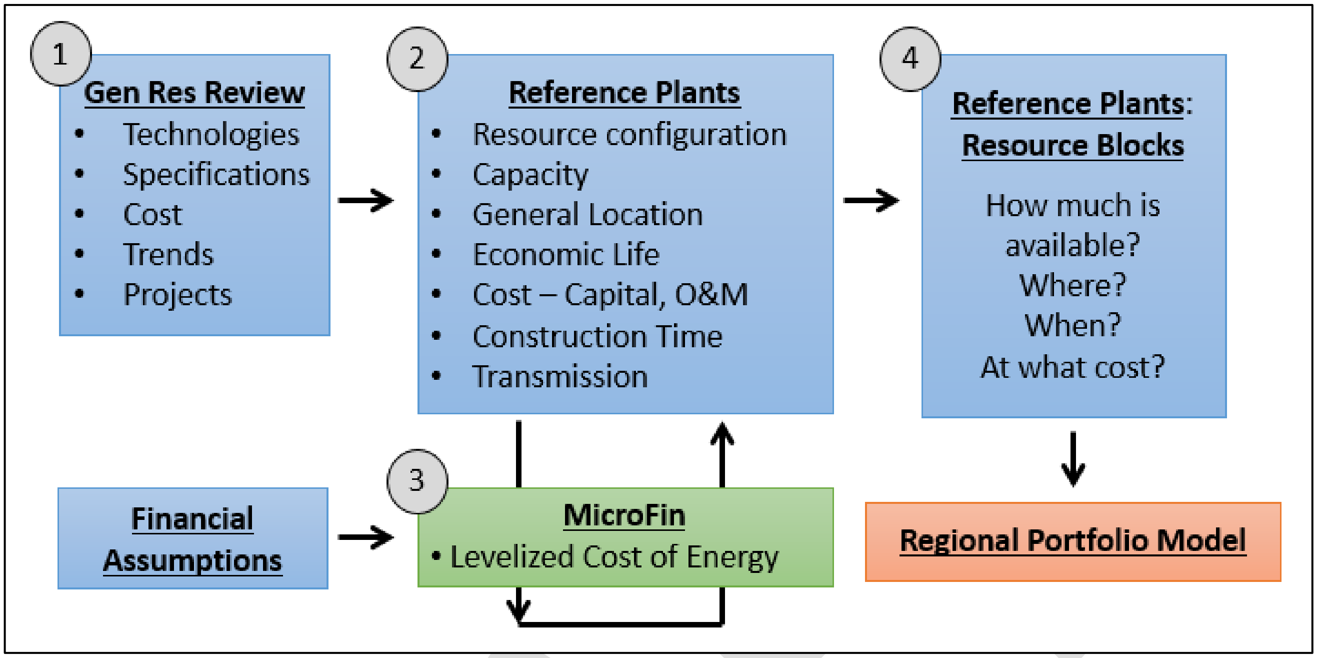
This appendix focuses on the development of reference plants for resources classified as primary, but includes a solar + battery storage example from the Long-Term category.

A **reference plant** is a collection of characteristics that describe a resource technology and its theoretical application in the region. It includes estimates of typical costs, logistics, and operating specifications. These reference plants become inputs to the Regional Portfolio Model as options for selection to fulfill future resource needs.

Generating Resources Assessment Methodology

This section describes the methodology for assessing the generating resource and energy storage technologies for consideration in the Seventh Power Plan. Staff, along with advice from the Council's Generating Resources Advisory Committee (GRAC), performed a review of generating resources and energy storage technologies having significance to the Seventh Power Plan. Reference plants for resources were developed, with many characteristics becoming inputs for further analysis in MicroFin - the finance model used to calculate both the fixed levelized cost, and the full levelized cost of energy (LCOE) for power generating resources. Resource potential is determined and added to the reference plant as resource blocks, which are input as options in the RPM for selection to fulfill future resource needs.

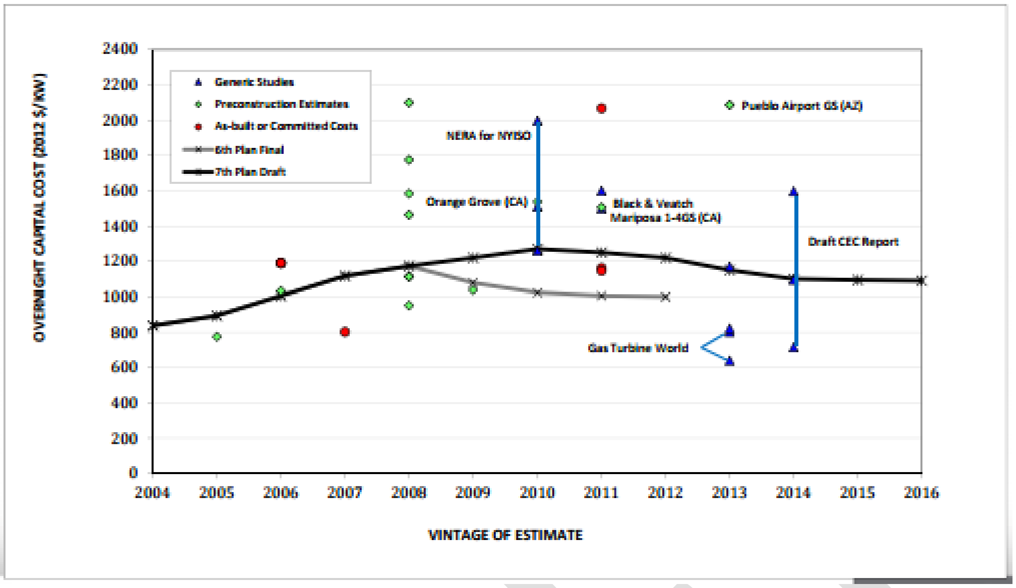
Figure H - 1: Generating Resources Assessment



When assessing potential resources and technologies, staff performs an extensive review of existing and planned projects both within the region and across the Western Electricity Coordinating Council (WECC) and nation. In addition, staff performs a literature review of publically-available reports, media sources, public utility commission filings, utility integrated resource plans, and manufacturer reports. Through this research, information such as capital and operating and maintenance (O&M) costs, technology performance, construction timelines, and plant lifetimes is gathered and used as the basis for developing cost estimates and configuring a realistic reference plant for the region.

Cost Estimates. The raw cost data used to develop reference plant cost estimates (capital and O&M) represent different vintages, project scopes, and year dollars, and may or may not include the costs of financing, escalation, and interest during construction. In some cases, highly detailed, disaggregated cost estimates are available, in other cases only a single number. Reported costs must be normalized to a common vintage, scope, year dollars, and to overnight value. The costs are plotted to determine trends and formulate an estimate for the reference plant. Figure H-2 is an example of a capital cost estimate plot for Aeroderivative gas turbines.

Figure H - 2: Capital Cost Estimate for Aeroderivative Gas Turbines



Several input characteristics are used to compute the levelized cost of energy and complete the assumptions for the reference plant. The capital and O&M cost are inputs to MicroFin, which calculates the levelized cost of the generating resource.

MicroFin. A financial revenue requirements model – Microfin - was used to calculate the levelized fixed cost and the full levelized cost of energy (LCOE) for each reference plant. The finance model calculates the annual cash flows which will satisfy revenue requirements over the plant lifetime. The annual cash flows are compressed and discounted into a dollar value – Net Present Value (NPV). The NPV is then converted into a level, annualized payment (like a home mortgage payment). Two important cost values are output from the model:

1. Levelized fixed cost ($ per kilowatt-year) represents the cost of building and maintaining a power plant over its lifetime and is a primary cost input to RPM.
2. LCOE ($ per megawatt-hour) is the cost per unit of energy the plant is expected to produce and which also includes variable costs such as fuel, and variable O&M.

The finance assumptions which are input to MicroFin have an impact on the resulting levelized costs. For example, each generating resource type has a set estimate for the overnight capital cost, regardless of who pays for the plant. However, the cost of capital to actually build the plant may vary based on the financial sponsor – such as a municipal or public utility, an investor-owned utility (IOU) or an independent power producer (IPP). Other important finance assumptions include the discount rate, rates of return, and investment tax credits. Important operating assumptions include gas price forecasts, O&M, and capacity factors. The financial assumptions for project sponsors are detailed in Table H-2 below.

Table H - 2: Financial Assumptions

Financial	Investor Owned Utility*	Independent Power Producer**
Federal Income Tax	35 %	35 %
Federal Investment Tax Credit (ITC)		Solar only - 30 % through year 2016, 10 % after
State Tax	5 %	5 %
Property Tax	1.4 %	1.4 %
Insurance	0.25 %	0.25 %
Debt Fraction	50 %	60 %
Debt Term	25 – 30 years	20 years
Debt Interest Rate (nominal)	6.69 %	6.69 %
Return On Equity (nominal)	10 %	12 %
Discount Rate	4 %	4 %

* Wind and Gas Plants
** Utility Scale Solar

Quantifying Environmental Effects

The Northwest Power Act requires the Council to estimate the incremental system cost of each new resource or conservation measure considered for inclusion in the plan's new resource strategy.

Environmental standards, the actions required for compliance, and the associated costs vary by geographic location and by the circumstances of different resources. These are best represented in the Council's planning process by representative plants characteristic of those that could be expected to be developed in the Northwest. With few exceptions, the sources of cost information for these plants available to the Council aggregate all of the costs of the plants, making it difficult to break out the embedded cost of environmental compliance. However, because the resource cost estimates are based on recently constructed or proposed plants, the Council assumes that the costs do include the cost of compliance with current and near-term planned environmental regulation.

Chapter 19 describes the Council's methodology for quantifying environmental costs and benefits. Appendix I describes in detail the effects on the environment associated with different types of generating resources considered for inclusion in the power plan's resource strategy, as well as the environmental regulations developed by other agencies of government to address those effects.

Resource Attributes

The following attributes are used to describe the resource reference plants for the Seventh Power Plan. Note that all costs are expressed in constant 2012 year dollars.

Configuration. The number of units (and generating capacity of each unit) that make up the complete reference plant. Also includes the air emissions controls, cooling (wet vs. dry), and other plant specifications.

Location. The general geographic location of the reference plant, which is important in properly accounting for plant attributes (e.g. capacity factor) and costs (transmission).

Earliest In-Operation Date (Year). The earliest date a reference plant is assumed to be in operation, taking into account development and construction. The RPM cannot select the resource before this date.

Construction Lead Time. The amount of time it takes from project conception to commissioning. For the Seventh Power Plan, there are two phases:

> **Development Period (Years)**. Includes planning and development, from the identification of need (for example in an utility IRP) to establishment of the EPC contract (which includes all siting and licensing, environmental assessments, and preliminary engineering).
>
> **Construction Period (Years)**. From the Notice to Proceed to complete construction and commissioning.

Developable Potential For modeling purposes in RPM, constraints were assigned to each reference plant. For some of the cases, the constraints on development are "soft", meaning the constraint may not be a true limit on the potential development of that reference plant, but is merely an estimate of the number of plants that could be built at the modeled cost. In other cases, the constraints may be considered more "hard", which could be caused by transmission capacity constraints at a given location.

Economic Life (Years). The assumed useful operating life of the plant.

Financial Sponsor. Power plants can be constructed by investor-owned utilities, consumer-owned utilities and independent power producer developers. Each of these entities uses different project financing mechanisms. The differing financing mechanisms and financial incentives available for some resources result in different total investment costs and annual capital service requirements for otherwise identical projects.

Capacity (MW). The lifecycle capacity in megawatts of the individual reference plant.

Capacity Factor (%). An estimate of the ratio of the actual annual output to the potential annual output if the plant is operated at full capacity. This is a useful value when looking at variable energy generation in different locations, such as wind and solar PV.

Fuel. The primary type of fuel burned (natural gas, oil, coal, etc.), its location of origin, and cost.

Heat Rate (Btu/kWh). A measure of the efficiency of which a generator converts fuel into electricity. Full load, net plant lifetime averages, expressed as higher heating values (HHV).

Overnight Capital Cost ($/kW). An estimate of the project development and construction cost. "Overnight" refers to what the cost would be if the plant were built instantly, or over one night. This cost constitutes a sum of the engineering, procurement, and construction (EPC) costs, plus owner's costs (costs incurred by the project developer – permits, licenses, land, project development costs, infrastructure, taxes, regulatory compliance costs, etc.).

All-In Capital Cost ($/kW). An estimate of the total investment cost related to capital, including the cost of securing financing, interesting during construction, and escalation during construction.

Fixed O&M Cost ($/kW-yr). An estimate of the fixed operation and maintenance cost for the reference plant, including operating and maintenance, labor and materials, and administrative overhead. Both routine maintenance, and major maintenance and capital replacement are assumed to be included.

Variable O&M Cost ($/MWh). An estimate of the variable operation and maintenance cost for the reference plant, including all costs that are a function of the amount of power produced. This includes consumables such as water, chemicals, lubricants, and catalysts, and waste disposal.

Transmission. The assumed transmission (existing or new) that is incorporated into the cost of the resource.

Levelized Fixed Cost ($/kW-yr). An estimate of the cost of planning, building and maintaining a power plant over its lifetime, on an annualized cost basis.

Levelized Cost of Energy ($/MWh). An estimate of the cost per unit of energy for a resource over its productive lifetime, and includes fixed costs, and variable costs such as variable O&M and fuel commodity costs under an assumed capacity factor.

GENERATING RESOURCE REFERENCE PLANTS

Combined Cycle Combustion Turbine

Description of Reference Plant. Three reference plants based on two slightly different types of combined cycle combustion turbines technologies (CCCT) were developed. The first is based on the Siemens H-Class in a one gas turbine by one steam engine configuration, utilizing wet cooling, and located on the East side of the Cascade mountains. The total baseload plant capacity is 370 megawatts and the heat rate is 6,770 British thermal units per kilowatt-hour. The second reference plant is based on the Mitsubishi Heavy Industries (MHI) J-Class in a one gas turbine by one steam engine configuration, utilizing dry cooling, also located on the East side. The total plant capacity is slightly larger at 425 megawatts and the heat rate is 6,704 British thermal units per kilowatt-hour. The third reference plant is based on MHI J-Class but set on the West side. It is assumed that a new CCCT on the West side would require additional costs associated with pipeline expansion. Tables H-3 and H-4 provide a summary of the plants.

Each plant is assumed to operate on natural gas supplied on a firm transportation contract. Location-specific adjustments were made for firm service cost estimates and for the impact of elevation on output. Emission controls include low-nitrogen oxide burners and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound control. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor.

Importance/Relevance to PNW. Combined cycle combustion turbines are the largest and most efficient of the gas-fired generating technologies. These versatile plants have the ability to replace baseload coal power, can act as a firming resource for variable renewable generation, and fill in gaps from reduced hydro power production during low water years. CCCTs emit carbon dioxide at significantly lower rates than coal plants, and may play a key role in helping to reduce overall carbon dioxide emissions as proposed in the Federal Clean Power Plan. This technology also benefits from the robust existing natural gas infrastructure system in the region, as well as plentiful and low cost fuel supply.

Development potential. Overall, the potential for CCCT development in the region is large. For modeling purposes in RPM, the *wet-cooled CCCT* reference plant on the East side was limited to 1,110 MW of total development (three plants) to represent the possibility of permitting constraints for plants with heavy water usage. Dry cooled units on the East side have significant potential for development since the technology is not a heavy water consumer, and there is ample pipeline capacity on the East side. The potential for CCCT development may be more limited on the West side where potential constraints on pipeline capacity could hamper or delay development.

Table H - 3: CCCT Reference Plants

Reference Plant	CCCT Adv 1 Wet Cool East	CCCT Adv 2 Dry Cool East	CCCT Adv 2 Dry Cool West
Configuration	1 gas turbine x 1 steam turbine and wet cooling system	1 gas turbine x 1 steam turbine and dry cool system	1 gas turbine x 1 steam turbine and dry cool
Note	Based on Siemens H-Class. Number of plants with wet cooling may be limited	Based on MHI J-Class	Based on MHI J-Class. Assumed to require gas pipeline expansion on West side
Location	East side	East side	West side
Earliest In-Operation Date	2020	2021	2021
Development Period (Years)	2	2	2
Construction Period (Years)	3	3	3
Economic Life (Years)	30	30	30
Financial Sponsor	IOU	IOU	IOU
Capacity (MW)	370	425	426
Fuel	Natural Gas East	Natural Gas East	Natural Gas West with pipeline expansion
Heat Rate (btu/kWh)	6,770	6,704	6,704
Overnight Capital Cost ($/kW)	1,147	1,287	1,287
Fixed O&M Cost ($/kW-yr)	15.37	15.37	15.37
Variable O&M Cost ($/MWh)	3.27	3.27	3.27
Transmission	BPA point to point	BPA point to point	BPA point to point with transmission deferral credit
Maximum build-out (MW) as modeled	1,110	5,950	1,278

Table H - 4: CCCT Cost Summary

Reference Plant Name	Cost Category	2020	2025	2030	2035
CCCT Adv 1 Wet Cool East	All-In Capital Cost ($/kW)	1,234	1,210	1,180	1,151
	Levelized Fixed Cost ($/kW-yr)	181.80	179.37	176.10	172.88
	Levelized Cost of Energy ($/MWh)*	75.68	78.48	80.12	80.47
CCCT Adv 2 Dry Cool East	All-In Capital Cost ($/kW)	1,384	1,357	1,324	1,292
	Levelized Fixed Cost ($/kW-yr)	195.97	193.27	189.68	186.16
	Levelized Cost of Energy ($/MWh)*	78.01	80.73	82.28	82.57
CCCT Adv 2 Dry Cool West	All-In Capital Cost ($/kW)	1,379	1,352	1,319	1,287
	Levelized Fixed Cost ($/kW-yr)	204.07	201.23	197.31	193.44
	Levelized Cost of Energy ($/MWh)*	82.76	85.23	86.52	86.58

* Capacity factor of 0.6 was applied

Notable changes since Sixth Power Plan analysis.

- When estimating the capital cost of combined cycle combustion turbines in the Sixth Power Plan, there was an assumption that the economic recession of 2008-09 was coming to an end and that prices would drop in 2010. In reality, it appears that the effects of the recession continued past 2010 and prices did not drop as quickly as expected. This resulted in a higher capital cost estimate for CCCT plants in 2016 than was anticipated for the same year in the Sixth Plan analysis.
- Since the Sixth Power Plan, combined cycle combustion turbines have continued to improve and become more efficient. The heat rate for the all CCCT technologies has improved (lowered) for reference plants in the Seventh Power Plan, as compared to the Sixth Plan.
- Since the Sixth Power Plan, natural gas fuel price forecasts have dropped significantly (45% drop in near term) lowering the overall levelized cost of energy.

Reciprocating Engine

Description of Reference Plant. The reciprocating engine reference plant is based off of the Wärtsilä 18V50SG natural gas engine with twelve, 18.3 megawatt modules. The total plant capacity is 220 megawatts and the heat rate is 8,370 British thermal units per kilowatt-hour. One reference plant is located on the East side, while two additional reference plants are located on the West side. West side reference plants were defined with and without expansion of the West-side gas pipeline system. There is assumed to be sufficient natural gas capacity on the East side. A firm gas transport contract is assumed. Air emission controls include a combined selective catalytic reduction and oxidation catalyst to reduce nitrogen oxides (NO_x), carbon monoxide and volatile organic compound emissions. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor. Tables H-5 and H-6 provide a summary of the plants.

Importance/Relevance to PNW. Traditionally, gas peakers (primarily frame units) were used to help shape and firm hydroelectric power in the Pacific Northwest. Technological advancements in both reciprocating engines and simple cycle combustion turbines have resulted in more flexible and efficient machines with fast start times and rapid response to system changes, leading to the ability to help meet short-term peak loads and integrate variable energy generation. Reciprocating engines in particular have the benefit of being modular and able to size according to need, and are very efficient. They are also not as sensitive to temperatures or elevations in terms of output, like the simple and combined cycle combustion turbines.

Development potential. Overall, the potential for reciprocating engine development in the region is large. The potential for development may be more limited on the West side where potential constraints on pipeline capacity could hamper or delay development.

Table H - 5: Reciprocating Engines Reference Plants

Reference Plant	Recip. Eng. East	Recip. Eng. West 1	Recip. Eng. West
Configuration	12 module generation set	12 module generation set	12 module generation set
Note		Assumed a limited number of plants (1) could be developed without gas pipeline expansion on west side	With gas pipeline expansion, multiple plants allowed
Location	East side	West side	West side
Earliest In-Operation Date	2018	2018	2020
Development Period (Years)	2	2	2
Construction Period (Years)	1	1	1
Economic Life (Years)	30	30	30
Financial Sponsor	IOU	IOU	IOU
Capacity (MW)	220	220	220
Fuel	Natural Gas East	Natural Gas West	Natural Gas West with pipeline expansion
Heat Rate (btu/kWh)	8,370	8,370	8,370
Overnight Capital Cost ($/kW)	1,300	1,300	1,300
Fixed O&M Cost ($/kW-yr)	10.00	10.00	10.00
Variable O&M Cost ($/MWh)	9.00	9.00	9.00
Transmission	BPA point to point	BPA point to point with transmission deferral credit	BPA point to point with transmission deferral credit
Maximum build-out (MW) as modeled	3,080	220	1,110

Table H - 6: Reciprocating Engine Cost Summary

Reference Plant Name	Cost Category	2020	2025	2030	2035
Recip. Eng. East	All-In Capital Cost ($/kW)	1,315	1,283	1,251	1,220
	Levelized Fixed Cost ($/kW-yr)	190.58	187.33	184.03	180.78
	Levelized Cost of Energy ($/MWh)*	142.54	144.84	146.10	145.79
Recip. Eng. West 1	All-In Capital Cost ($/kW)	1,315	1,283	1,251	1,220
	Levelized Fixed Cost ($/kW-yr)	168.33	164.96	161.59	158.35
	Levelized Cost of Energy ($/MWh)*	136.37	138.32	139.30	138.79
Recip. Eng. West	All-In Capital Cost ($/kW)	1,315	1,283	1,251	1,220
	Levelized Fixed Cost ($/kW-yr)	207.59	203.97	200.27	196.55
	Levelized Cost of Energy ($/MWh)*	154.30	156.13	156.96	156.23

* Capacity factor of 0.25 was applied

Notable changes since Sixth Power Plan analysis.

- When estimating the capital cost of gas peakers in the Sixth Power Plan, there was an assumption that the economic recession of 2008-09 was coming to an end and that prices would drop in 2010. In reality, it appears that the effects of the recession continued past 2010 and prices did not drop as quickly as expected. This resulted in a higher capital cost estimate for gas peaking power plants in 2016 than was anticipated for the same year in the Sixth Plan analysis.
- Since the Sixth Power Plan, gas peaking technologies have continued to improve and become more efficient. The heat rate for the all gas peaking technologies has improved (lowered) for reference plants in the Seventh Power Plan, as compared to the Sixth Plan.
- All the gas peaking technology reference plants are configured to approximate the capacity of the most recent gas peaker developed in the region – Portland General Electric's Port Westward II, a 220 megawatt reciprocating engine.
- Since the Sixth Power Plan, natural gas fuel price forecasts have dropped significantly (45% drop in near term) lowering the overall levelized cost of energy for gas plants.

Simple Cycle - Aeroderivative Gas Turbine -

Description of Reference Plant. The Aeroderivative gas turbine reference plant is based on the General Electric LM6000PF SPRINT, with four, 47 megawatt turbine generators. The total plant capacity is 178 megawatts and the heat rate is 9,477 British thermal units per kilowatt-hour. One reference plant is located on the east side, while two additional reference plants are located on the West side. West side reference plants were defined with and without new build out of the West-side gas pipeline system. There is assumed to be sufficient natural gas capacity on the east side. Air emission controls include water injection and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor. Tables H-7 and H-8 provide a summary of the plants.

Importance/Relevance to PNW. Traditionally, gas peakers (primarily frame units) were used to help shape and firm hydroelectric power in the Pacific Northwest. Technological advancements in both reciprocating engines and simple cycle combustion turbines have resulted in more flexible and efficient machines with fast start times and rapid response to system changes, leading to the ability to help meet short-term peak loads and integrate variable energy generation. Aeroderivative plants in particular have been popular developments in the Western Electricity Coordinating Council (WECC) region over the past decade.

Development potential. Overall, the potential for Aeroderivative gas turbine development in the region is large. The potential for development may be more limited on the West side where potential constraints on pipeline capacity could hamper or delay development.

Table H - 7: Aeroderivative Gas Turbine Reference Plants

Reference Plant	Aero GT East	Aero GT West 1	Aero GT West
Configuration	4 GT x 47 MW	4 GT x 47 MW	4 GT x 47 MW
Note		Assumed a limited number of plants (1) could be developed without gas pipeline expansion on west side	With gas pipeline expansion, multiple plants allowed
Location	East side	West side	West side
Earliest In-Operation Date	2018	2018	2020
Development Period (Years)	2	2	2
Construction Period (Years)	1	1	1
Economic Life (Years)	30	30	30
Financial Sponsor	IOU	IOU	IOU
Capacity (MW)	178	179	179
Fuel	Natural Gas East	Natural Gas West	Natural Gas West with pipeline expansion
Heat Rate (btu/kWh)	9,477	9,477	9,477
Overnight Capital Cost ($/kW)	1,111	1,107	1,107
Fixed O&M Cost ($/kW-yr)	25.00	25.00	25.00
Variable O&M Cost ($/MWh)	5.00	5.00	5.00
Transmission	BPA point to point	BPA point to point with transmission deferral credit	BPA point to point with transmission deferral credit
Maximum build-out (MW) as modeled	2,492	179	1,074

Table H - 8: Aeroderivative Gas Turbine Cost Summary

Reference Plant Name	Cost Category	2020	2025	2030	2035
Aero GT East	All-In Capital Cost ($/kW)	1,124	1,096	1,069	1,043
	Levelized Fixed Cost ($/kW-yr)	191.76	188.58	185.32	181.99
	Levelized Cost of Energy ($/MWh)*	145.21	148.02	149.65	149.47
Aero GT West 1	All-In Capital Cost ($/kW)	1,120	1,092	1,065	1,039
	Levelized Fixed Cost ($/kW-yr)	169.63	166.34	163.01	159.69
	Levelized Cost of Energy ($/MWh)*	139.61	142.05	143.37	142.96
Aero GT West	All-In Capital Cost ($/kW)	1,120	1,092	1,065	1,039
	Levelized Fixed Cost ($/kW-yr)	214.09	210.50	206.80	202.94
	Levelized Cost of Energy ($/MWh)*	159.91	162.21	163.36	162.71

* Capacity Factor of 0.25 was applied

Notable changes since Sixth Power Plan analysis.

- When estimating the capital cost of gas peakers in the Sixth Power Plan, there was an assumption that the economic recession of 2008-09 was coming to an end and that prices would drop in 2010. In reality, it appears that the effects of the recession continued past 2010 and prices did not drop as quickly as expected. This resulted in a higher capital cost estimate for gas peaking power plants in 2016 than was anticipated for the same year in the Sixth Plan analysis.
- Since the Sixth Power Plan, gas peaking technologies have continued to improve and become more efficient. The heat rate for the all gas peaking technologies has improved (lowered) for reference plants in the Seventh Power Plan, as compared to the Sixth Plan.
- All the gas peaking technology reference plants are configured to approximate the capacity of the most recent gas peaker developed in the region – Portland General Electric's Port Westward II, a 220 megawatt reciprocating engine.
- Since the Sixth Power Plan, natural gas fuel price forecasts have dropped significantly (45% drop in near term) lowering the overall levelized cost of energy for gas plants.

Simple Cycle - Frame Gas Turbine

Description of Reference Plant. The frame gas turbine reference plant is based off of the General Electric 7F5S with one, 216 megawatt turbine generator. The total plant capacity is therefore 216 megawatts and the heat rate is 10,266 British thermal units per kilowatt-hour. One reference plant is located on the east side, while two additional reference plants are located on the West side. West side reference plants were defined with and without new build out of the West-side gas pipeline system. There is assumed to be sufficient natural gas capacity on the East side. A firm gas transport contract is assumed. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor. Tables H-9 and H-10 provide a summary of the plants.

Importance/Relevance to PNW. Traditionally, gas peakers (primarily frame units) were used to help shape and firm hydroelectric power in the Pacific Northwest. Technological advancements in both reciprocating engines and simple cycle combustion turbines have resulted in more flexible and efficient machines with fast start times and rapid response to system changes, leading to the ability to help meet short-term peak loads and integrate variable energy generation. The frame gas turbine plant has lower upfront capital costs than the Aeroderivative, but runs at a lower efficiency and is less flexible.

Development potential. Overall, the potential for frame gas turbine development in the region is large. The potential for development may be more limited on the West side where potential constraints on pipeline capacity could hamper or delay development.

Table H - 9: Frame Gas Turbine Reference Plants

Reference Plant	Frame GT East	Frame GT West 1	Frame GT West
Configuration	1 GT x 216 MW	1 GT x 216 MW	1 GT x 216 MW
Note		Assumed a limited number of plants (1) could be developed without gas pipeline expansion on west side	With gas pipeline expansion, multiple plants allowed
Location	East side	West side	West side
Earliest In-Operation Date	2018	2018	2020
Development Period (Years)	2	2	2
Construction Period (Years)	1	1	1
Economic Life (Years)	30	30	30
Financial Sponsor	IOU	IOU	IOU
Capacity (MW)	200	201	201
Fuel	Natural Gas East	Natural Gas West	Natural Gas West with pipeline expansion
Heat Rate (btu/kWh)	10,266	10,266	10,266
Overnight Capital Cost ($/kW)	808	805	805
Fixed O&M Cost ($/kW-yr)	7.00	7.00	7.00
Variable O&M Cost ($/MWh)	10.00	10.00	10.00
Transmission	BPA point to point	BPA point to point with transmission deferral credit	BPA point to point with transmission deferral credit
Maximum build-out (MW) as modeled	2,800	201	1,005

Table H - 10: Frame Gas Turbine Cost Summary

Reference Plant Name	Cost Category	2020	2025	2030	2035
Frame GT East	All-In Capital Cost ($/kW)	817	797	777	758
	Levelized Fixed Cost ($/kW-yr)	147.64	145.49	143.26	140.95
	Levelized Cost of Energy ($/MWh)*	134.45	138.10	140.48	140.86
Frame GT West 1	All-In Capital Cost ($/kW)	814	794	775	755
	Levelized Fixed Cost ($/kW-yr)	125.97	123.70	121.40	119.10
	Levelized Cost of Energy ($/MWh)*	129.44	132.69	134.72	134.86
Frame GT West	All-In Capital Cost ($/kW)	814	794	775	755
	Levelized Fixed Cost ($/kW-yr)	174.13	171.54	168.84	165.95
	Levelized Cost of Energy ($/MWh)*	151.43	154.53	156.38	156.25

* Capacity factor of 0.25 was applied

Notable changes since Sixth Power Plan analysis.

- When estimating the capital cost of gas peakers in the Sixth Power Plan, there was an assumption that the economic recession of 2008-09 was coming to an end and that prices would drop in 2010. In reality, it appears that the effects of the recession continued past 2010 and prices did not drop as quickly as expected. This resulted in a higher capital cost estimate for gas peaking power plants in 2016 than was anticipated for the same year in the Sixth Plan analysis.
- Since the Sixth Power Plan, gas peaking technologies have continued to improve and become more efficient. The heat rate for the all gas peaking technologies has improved (lowered) for reference plants in the Seventh Power Plan, as compared to the Sixth Plan.
- All the gas peaking technology reference plants are configured to approximate the capacity of the most recent gas peaker developed in the region – Portland General Electric's Port Westward II, a 220 megawatt reciprocating engine.
- Since the Sixth Power Plan, natural gas fuel price forecasts have dropped significantly (45% drop in near term) lowering the overall levelized cost of energy for gas plants.

Utility Scale Solar Photovoltaic

Description of Reference Plants. Four reference plants were defined for utility scale solar. All of the plant capacities are defined in terms of megawatts (alternating current - AC) configured with crystalline silicon based modules mounted on single-axis trackers. The reference plants are modeled to have a 30-year lifetime with an annual degradation of one percent. To be consistent with utility scale solar development across the US, the project sponsor was assumed to be an independent power producer. Due to the rapidly changing cost environment for solar technology, a forecast of capital costs was developed, along with a low and high cost range. The first solar PV reference plant is a 20 megawatt (AC) plant located in Southern Idaho and is based on the mid-range capital cost estimate. A larger plant, 50 megawatt (AC) in the same location but with the low range estimated capital and O&M cost. The third reference plant located in Southern Idaho contains an estimate for additional transmission related costs to bring the power to the West side. One reference plant was defined for the West side, where the solar resource is not as favorable. The low cost estimate was used for this plant. Tables H-11 and H-12 provide a summary of the plants.

Importance/Relevance to PNW. Although current presence in the region is limited, activity has recently picked up in Southern Idaho. As solar installation costs continue to decline, solar power may become more and more significant to the region; although without storage capability, solar power remains a variable energy resource which does not contribute to peak capacity in the winter.

Development potential. The potential for utility scale solar development in the region is large, particularly in Southern Idaho where the best capacity factors could be achieved. Limited existing transmission capacity from Southern Idaho to the West side load centers could create a hurdle for more extensive development. Should installation costs continue to decline, significant solar development could also occur in western Oregon and Washington where transmission may be more available.

Table H - 11: Solar PV Reference Plants

Reference Plant	Solar PV S. ID	Solar PV S. ID w/ Transmission Expansion	Solar PV Low Cost S. ID	Solar PV Low Cost W. WA
Configuration	20 MW_{ac} installation with crystalline silicon panels and single axis tracker system	20 MW_{ac} installation with crystalline silicon panels and single axis tracker system	50 MW_{ac} installation with crystalline silicon panels and single axis tracker system	50 MW_{ac} installation with crystalline silicon panels and single axis tracker system
Note	Mid-range capital cost estimate	Mid-range capital cost estimate	Low range capital cost estimate	Low range capital cost estimate
Location	Southern Idaho	Southern Idaho	Southern Idaho	Western WA
Earliest In-Operation Date	2018	2021	2020	2020
Development Period (Years)	2	2	2	2
Construction Period (Years)	1	1	1	1
Economic Life (Years)	30	30	30	30
Financial Sponsor	IPP	IPP	IPP	IPP
Investment Tax Credit*	30%/10 %	30%/10 %	30%/10 %	30%/10 %
Capacity (MW)	17.4	17.4	48	48
Capacity Factor	0.262	0.262	0.262	0.189
Overnight Capital Cost ($/kW)	2,413	2,413	1,685	1,685
Fixed O&M Cost ($/kW-yr)	16.63	16.63	11.62	11.61
Variable O&M Cost ($/MWh)	0	0	0	0
Transmission	Idaho Power	Transmission Expansion & BPA	Idaho Power	BPA point to point
Maximum build-out (MW) as modeled	989	989	989	1440

* ITC at 30% through year 2016, and 10% after

Table H - 12: Solar PV Cost Summary

Reference Plant Name	Cost Category	2020	2025	2030	2035
Solar PV S. ID	All-In Capital Cost ($/kW)	2,237	2,058	1,948	1,862
	Levelized Fixed Cost ($/kW-yr)	222.72	206.25	195.22	185.17
	Levelized Cost of Energy ($/MWh)	99.53	92.36	87.56	83.17
Solar PV S. ID w/ Transmission Expansion	All-In Capital Cost ($/kW)	2,238	2,058	1,948	1,862
	Levelized Fixed Cost ($/kW-yr)	311.00	294.68	283.69	273.35
	Levelized Cost of Energy ($/MWh)	137.99	130.89	126.11	121.59
Solar PV Low Cost S. ID	All-In Capital Cost ($/kW)	1,388	1,167	1,006	1,006
	Levelized Fixed Cost ($/kW-yr)	146.80	126.87	111.88	110.54
	Levelized Cost of Energy ($/MWh)	66.45	57.77	51.25	50.65
Solar PV Lower Cost W. WA	All-In Capital Cost ($/kW)	1,388	1,167	1,006	1,006
	Levelized Fixed Cost ($/kW-yr)	146.59	126.66	111.67	110.32
	Levelized Cost of Energy ($/MWh)	88.64	76.60	67.55	66.73

Notable changes since Sixth Power Plan analysis. Costs estimates for utility scale solar installations have dropped more than 60 percent since the previous plan was completed. This resulted in including solar PV as an input to RPM in the Seventh Power Plan, whereas in the previous plan it was not included.

Wind Power: Utility Scale, Onshore

Description of Reference Plant. The wind power reference plant consists of forty, 2.5 megawatt conventional three-blade wind turbine generators, creating a total plant installed nameplate capacity of 100 megawatts. The plant is assumed to include in-plant electrical and control systems, interconnection facilities and on-site roads, meteorological towers and support facilities. One reference plant is located in the Columbia Basin, while an additional four reference plants are located in central Montana with various transmission requirements. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor. Tables H-13 and H-14 provide a summary of the plants.

Importance/Relevance to PNW. Wind power has played a significant role in the region over the past decade. With the Renewable Portfolio Standards enacted by Oregon, Washington, Montana, and others in WECC, federal incentives, and PURPA projects spurring development in the Pacific Northwest, the region has installed about 7,500 megawatts capacity (~8,500 megawatts when including the PacifiCorp Wyoming projects). There has been a significant lull in wind development since the boom in 2012, due in part to uncertainty over federal tax incentives, but also due to utilities reaching their near-term RPS goals. As the next round of goals approaches in 2020, the region is likely to undergo another development of renewable resources, including wind power.

Developable potential. The potential for wind development in the region is large, particularly in the Columbia Basin where transmission is available. Locations in Montana have a robust wind resource, but lack substantial transmission to transfer power to the west side load centers. Transmission upgrades may be required before extensive wind development could take place in Montana.

Table H - 13: Wind Power Reference Plants

Reference Plant	Wind Columbia Basin	Wind MT w/existing Transmission	Wind MT w/ new Transmission	Wind MT w/ Transmission Upgrade	Wind MT w/ Colstrip Transmission
Configuration	40 x 2.5 MW wind turbine generators	40 x 2.5 MW wind turbine generators	40 x 2.5 MW wind turbine generators	40 x 2.5 MW wind turbine generators	40 x 2.5 MW wind turbine generators
Note		Very limited transmission available to bring to western load centers	New 230kV transmission line rolled into capital cost	New 230kV transmission line and Path 8 Upgrade	Using Colstrip Transmission
Location	OR/WA	MT	MT	MT	MT
Earliest In-Operation Date	2019	2019	2020	2020	n/a
Development Period (Years)	2	2	2	2	2
Construction Period (Years)	2	2	2	2	2
Economic Life (Years)	25	25	25	25	25
Financial Sponsor	IOU	IOU	IOU	IOU	IOU
Capacity (MW)	100	100	100	100	100
Capacity Factor	0.32	0.40	0.40	0.40	0.40
Overnight Capital Cost ($/kW)	2,240	2,240	2,349	2,349	2,240
Fixed O&M Cost ($/kW-yr)	35.00	35.00	35.00	35.00	35.00
Variable O&M Cost ($/MWh)	2.00	2.00	2.00	2.00	2.00
Transmission	BPA point to point	NorthWestern Energy, Montana Intertie, BPA	NorthWestern Energy, Montana Intertie, BPA	NorthWestern Energy, Montana Intertie, BPA	Colstrip Trans. System, Montana Intertie, BPA
Maximum build-out (MW) as modeled	6,500	100	200	900	700

Table H - 14: Wind Power Cost Summary

Reference Plant Name	Cost Category	2020	2025	2030	2035
Wind Columbia Basin	All-In Capital Cost ($/kW)	2,307	2,250	2,194	2,140
	Levelized Fixed Cost ($/kW-yr)	303.39	297.50	291.65	286.08
	Levelized Cost of Energy ($/MWh)	110.33	108.24	106.16	104.17
Wind MT w/existing Transmission	All-In Capital Cost ($/kW)	2,307	2,250	2,194	2,140
	Levelized Fixed Cost ($/kW-yr)	351.56	345.82	340.04	334.34
	Levelized Cost of Energy ($/MWh)	102.45	100.82	99.18	97.55
Wind MT w/ new Transmission	All-In Capital Cost ($/kW)	2,419	2,359	2,301	2,245
	Levelized Fixed Cost ($/kW-yr)	363.04	357.04	351.00	345.07
	Levelized Cost of Energy ($/MWh)	105.73	104.02	102.31	100.61
Wind MT w/ Transmission Upgrade	All-In Capital Cost ($/kW)	2,419	2,359	2,301	2,245
	Levelized Fixed Cost ($/kW-yr)	375.54	369.59	363.59	357.65
	Levelized Cost of Energy ($/MWh)	109.29	107.61	105.90	104.20
Wind MT w/ Colstrip Transmission	All-In Capital Cost ($/kW)	2,307	2,250	2,194	2,140
	Levelized Fixed Cost ($/kW-yr)	322.50	316.63	310.77	305.12
	Levelized Cost of Energy ($/MWh)	94.16	92.49	90.82	89.21

Notable changes since Sixth Power Plan analysis.

- When estimating the capital cost of wind power plants in the Sixth Power Plan, there was an assumption that the economic recession of 2008-09 was coming to an end and that prices would drop in 2010. In reality, it appears that the effects of the recession continued past 2010 and prices did not drop as quickly as expected. This resulted in a higher capital cost estimate for wind power plants in 2016 than was anticipated for the same year in the Sixth Plan analysis.

- As wind turbine technology has improved, so too have capacity factors. Hub heights have increased and improved the ability of the turbines to achieve a greater wind sweep area. There is also more real world data available to analyze what annual capacity factors are being achieved in certain areas. The estimated capacity factor for the reference wind power plants in Montana was improved from 38 percent in the Sixth Power Plan, to 40 percent in the Seventh Power Plan. The estimated capacity factor for the Columbia Gorge area remained unchanged at 32 percent due to previous build-out of the better wind resource sites.
- The economic life of wind power plants was 20 years in the Sixth Plan, and has been increased to 25 years in the Seventh Power Plan based on real world examples, power purchase agreements, and utility IRP assumptions.
- In the Sixth Power Plan, the federal Production Tax Credit (PTC) was incorporated in the levelized cost calculation. Because the PTC is currently expired (as of October 2015), it has not been incorporated in the Seventh Power Plan.

Transmission

The common point of reference for the costs of new generating resources is the wholesale delivery point to local load serving areas. Estimates for the costs of transmission from the point of the generating project interconnection to the wholesale point of delivery are included in the overall estimated generating resource cost. Oregon and Washington resources serving Oregon and Washington loads include the Bonneville Power Administration transmission rate for long term, firm point to point transmission of $20/kW-year. Integration rates for variable resources such as wind ($14.76/kW-yr) and solar ($2.52/kW-yr)[1] were included when appropriate for the wind and solar generating resources.

In working up the generation models for utility scale solar in Southern Idaho, two cases were developed. For existing transmission capacity (*Solar PV S. ID*), the Idaho Power transmission rates ($22.71/kW-yr) were used, including an estimate for solar integration[2] ($2.50/MWh). In order to bring additional solar power from Southern Idaho to the western load centers in Oregon and Washington, new transmission may be required. The cost of new transmission for this case (*Solar PV S. ID w/Trans. Expan.*) was estimated using a proposed transmission project - B2H Boardman to Hemingway[3] - as a proxy.

The amount of transmission capacity which could bring wind power from Montana to the western load centers in Oregon and Washington is limited. Investments in future transmission projects and

[1] http://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/2014%20Rate%20Schedule%20Summary_10-01-13.pdf

[2] https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/solar/SolarIntegrationStudy.pdf

[3] https://www.wecc.biz/TransmissionExpansionPlanning/Lists/Project

upgrades may be required for significant quantities of wind power to reach the West. One reference case for Montana wind was estimated with existing transmission, and three Montana wind reference cases were developed which include cost estimates of new or expanded transmission. An existing transmission case (*Wind MT w/existing Trans.*) includes transmission rates for NorthWestern Energy Transmission[4], BPA IM-14 Montana Intertie, and BPA Point to Point Transmission. The second reference case (*Wind MT w/new Trans.)* has an estimate for a new 230kV line included in the cost, in addition to the existing transmission path. The third case (Wind MT w/Trans. Upgrade) includes the new 230kV line estimate in combination with an estimate of the proposed Path 8/CTS[5] upgrade which could relieve congestion on Path 8 and provide additional transmission for renewable power from Broadview Montana to the Mid-Columbia area. The final Montana Wind case (*Wind MT w/Colstrip Transmission*) includes estimated costs of existing transmission CTS, BPA IM-14 Montana Intertie, and BPA Point to Point Transmission if CTS transmission was available for wind.

Long-term Resource: Utility Scale Solar PV + Battery Energy Storage System

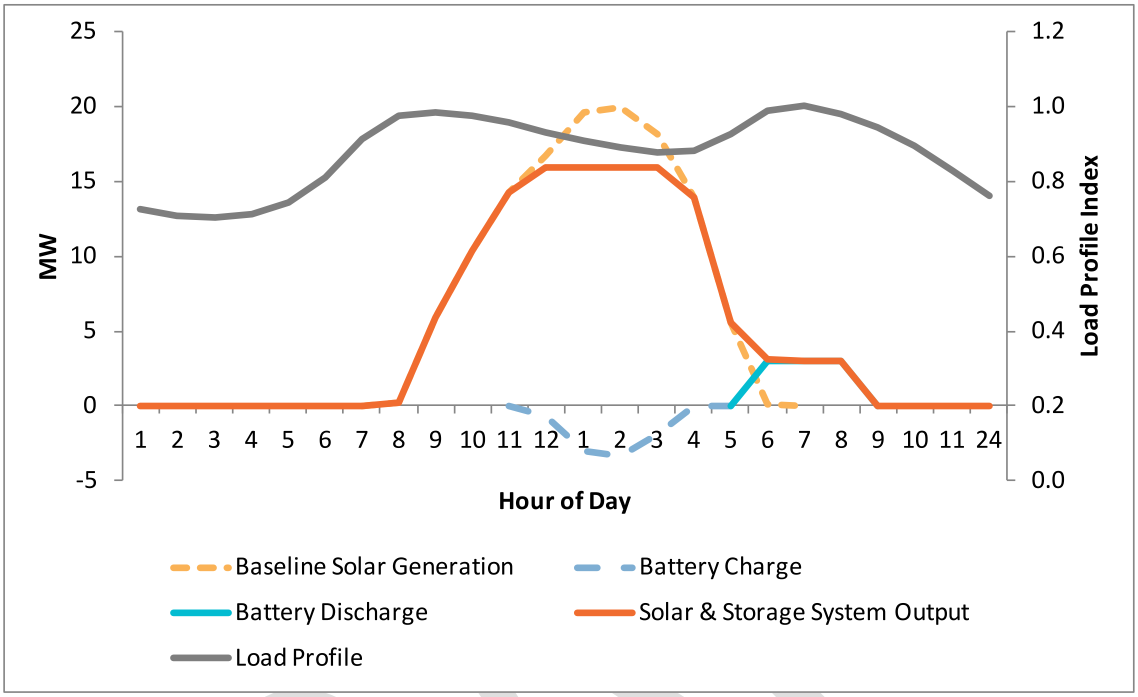
The pairing of solar with battery storage could provide additional benefits over solar alone, and has the potential to create a firm, dispatchable source of renewable energy. For example, during the day dynamic cloud conditions can hamper solar PV electricity generation, resulting in variable output. An integrated battery energy storage system (BESS) could smooth the solar output to provide a steadier source of electricity. With an integrated BESS, a solar PV plant could deliver electricity over a wider range of hours, such as in the evening or nighttime. By strategically charging a battery system during the day when solar production is high, storing the energy and discharging the battery in the evening or night, a solar PV plant could cover an expanded range of load conditions. Separately, solar technologies and battery energy storage technologies have been declining in terms of cost. These technologies have been installed as stand-alone systems, but efforts may be converging to install combined solar and battery systems on utility-scale levels. For example, the Kauai Island Utility Cooperative in Hawaii has signed a deal with SolarCity to purchase power from a proposed, fully-dispatchable utility-scale solar facility which could deliver electricity in the night time.[6]

Figure H - 3 displays an example of a modeled utility scale solar PV plant coupled with an integrated battery energy storage system. The solar PV plant in the example is modeled as a grid-connected, 50 megawatt (alternating current) single-axis tracker plant in Western Washington. The battery storage system is modeled as a ten megawatt Lithium-ion system with discharge capability of up to four hours. The chart shows how the solar PV and storage system might be utilized over a winter day in order to provide generation after the sun has set. The grey line shows a typical hourly load pattern for a winter day in the region with peaks in the morning and evening. The dashed yellow line displays the expected solar PV generation, with peak generation in the early afternoon and dropping to zero in the early evening. In this single day example, the battery storage system could be charged

[4] http://www.oasis.oati.com/NWMT/NWMTdocs/Schedule_7_-_Firm_PTP_Transmission_Service.pdf
[5] https://www.wecc.biz/TransmissionExpansionPlanning/Lists/Project
[6] http://www.bizjournals.com/pacific/news/2015/09/09/kauai-utility-signs-deal-with-solarcity-on-energy.html

in the afternoon using solar PV generation, and discharged in the evening time to provide output for the evening peak load. The orange line shows the overall system output.

Figure H - 3: Modeled Example of Solar + Battery System



The U.S. Department of Energy has developed near-term and long-term cost and performance targets for battery systems, including lithium-ion, flow, and other battery technologies. The near-term capital cost target is $1,750 per kilowatt, and the longer term target is $1,250 per kilowatt.[7] Currently, lithium-ion systems fall in a cost range from around $2,000 to $4,000 per kilowatt.[8] In the 2013 Portland General Electric Integrated Resource Plan, an estimate of the capital costs for a lithium-ion battery system came in at $2,380 per kilowatt[9].

This information was used to develop a cost estimate for a potential solar + battery system comprised of a 50 megawatts (alternating current) utility scale solar plant and a 10 megawatt Lithium-ion battery energy storage system. As shown in Figure H – 3, the plant is assumed to utilize its own solar generation to charge the battery system during the day, and discharge the battery system in the evening after sunset. The battery system is assumed to have an 85 percent round trip efficiency, meaning for every 0.85 megawatt the battery delivers to the grid, 1.0 megawatt of solar generation was consumed to charge the system. In addition, in order to prolong battery life, the minimum charge level of the battery was set to ten percent. Starting in the year 2020, the capital cost estimate for the battery system was $2,380/kilowatt hour, and was modeled to decline to $1,750/kilowatt hour by year 2025 and $1,250/kilowatt by the year 2030. The Investment Tax Credit

[7] Grid Energy Storage, U.S. Department of Energy, December 2013
[8] DOE/EPRI Electricity Storage Handbook, February 2015
[9] https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp_appG.pdf

of 10% was applied to the entire project, since the battery was assumed to be charged by the solar plant. An estimate was made for both the medium and low cost solar reference plant estimates. The cost estimate did not include a battery management system due to a lack of information. Battery management systems may be necessary to optimally integrate the solar plant with the battery. The cost information for the system is summarized in table H-15 and H-16. Because this is an emerging technology, the reference plants were not input to RPM.

Table H - 15: Solar + Battery Storage Plants

Reference Plant	Solar PV+Battery Storage System – W. WA	Low Cost Solar PV+Battery Storage System – W. WA
Configuration	50 MWac solar installation with crystalline silicon panels and single axis tracker system. Coupled with a 10 MWac Lithium-Ion battery system with 85% round trip efficiency and a 10% minimum state of charge	50 MWac solar installation with crystalline silicon panels and single axis tracker system. Coupled with a 10 MWac Lithium-Ion battery system with 85% round trip efficiency and a 10% minimum state of charge
Note	Mid-range capital cost estimate for solar with investment tax credit applied to entire project	Mid-range capital cost estimate for solar with investment tax credit applied to entire project
Location	Western WA	Western WA
Earliest In-Operation Date	2020	2020
Development Period (Years)	2	2
Construction Period (Years)	1	1
Economic Life (Years)	20	20
Financial Sponsor	IPP	IPP
Investment Tax Credit*	30%/10%	30%/10%
Capacity (MW)	48	48
Capacity Factor	0.189	0.189
Overnight Capital Cost ($/kW)**	2,657	1,837
Fixed O&M Cost ($/kW-yr)**	16.99	11.33
Variable O&M Cost ($/MWh)	0	0
Transmission	BPA point to point	BPA point to point

* ITC applied to entire solar + battery system, 30% through 2016, 10% following

** For construction year 2019

Table H - 16: Solar + Battery Storage Cost Summary

Reference Plant Name	Cost Category	2020	2025	2030	2035
Solar PV/Battery Storage System – W. WA	All-In Capital Cost ($/kW)	2,751	2,436	2,218	2,132
	Levelized Fixed Cost ($/kW-yr)	321.48	287.19	262.25	249.27
	Levelized Cost of Energy ($/MWh)*	195.31	174.48	159.34	151.46
Low Cost Solar PV/Battery Storage System – W. WA	All-In Capital Cost ($/kW)	1,901	1,545	1,276	1,276
	Levelized Fixed Cost ($/kW-yr)	228.70	190.03	160.15	157.95
	Levelized* Cost of Energy ($/MWh)*	138.97	115.49	97.34	96.01