GOLDENDALE ENERGY STORAGE HYDROELECTRIC PROJECT

Federal Energy Regulatory Commission Project No. 14861

Klickitat County, Washington

FINAL LICENSE APPLICATION
Exhibit D: Statement of Cost and Financing

For:

FFP Project 101, LLC

June 2020

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Acronyms and Abbreviations

Applicant	FFP Project 101, LLC
BMP	best management practice
E/M	electro-mechanical
FERC	Federal Energy Regulatory Commission
KPUD	Public Utility District No. 1 of Klickitat County, Washington
Li-ion	Lithium Ion
MW	megawatt
MWh	megawatt-hour
OPCC	Opinion of Probable Cost of Construction
PM&E	protection, mitigation, and enhancement
Project	Goldendale Energy Storage Project No. 14861
USBR	United States Bureau of Reclamation
WSI	West Surface Impoundment

1.0 STATEMENT OF PROJECT COSTS AND FINANCING

The following exhibit discusses cost and financing of the proposed Goldendale Energy Storage Project No. 14861 (Project) to be located near Goldendale, Washington, in Klickitat County, Washington, and Sherman County, Oregon. The proposed Project will be a new energy storage facility proposed by FFP Project 101, LLC (the Applicant).

Table 1-1 includes a breakdown of Project development costs. The table includes a total cost for each major item, interest during construction, and other general expenses. The table includes pooled contingencies on a p80 basis.[1]

The capital costs of environmental measures are included Table 1-1 and broken out in detail in Table 1-2. The capital costs of environmental measures listed in Table 1-2 are the costs expected at the time the measures will be implemented, with sufficient contingency added for the measures to be completed. Capital costs for environmental measures are subject to a change based on additional comments and consultation during the Federal Energy Regulatory Commission (FERC) licensing process.

Table 1-1: Expected Capital Costs for the Goldendale Pumped Storage Project

Item / Description	OPCC (October $2016)	OPCC (July $2019)
Project Characteristics		
Approximate Installed Capacity (MW)	1,200	1,200
Assumed Number of Units (Variable Speed)	3	3
Assumed Average Static Head (feet)	2,360	2,360
Assumed Usable Storage Volume (acre-feet)	7,100	7,100
Approximate Energy Storage (MWh)	14,745	14,745
Approximate Hours of Storage @ 1,200 MW	12	12
Direct Costs / USBR CCT Composite Trend Index	386	423
Reservoirs and Dams		
Upper Reservoir Dams	$238,700,000	$262,000,000
Lower Reservoir Dams	$171,400,000	$188,000,000
Upper Reservoir Liner	$19,000,000	$21,000,000
Lower Reservoir Liner	$19,000,000	$21,000,000
Stream Diversion	Included in temporary facilities and site preparation cost	Included in temporary facilities and site preparation cost
Spillway	Assumed Not Required	Assumed Not Required
Powerhouse Structure Civil Works	$138,000,000	$151,000,000
Water Conveyance System		
Upper Reservoir I/O Structure	$12,000,000	$13,000,000
Vertical Shaft	$50,000,000	$55,000,000
Horizontal Power Tunnel and Manifold	$57,000,000	$62,000,000

[1] P80 describes the level of confidence in cost estimate as a percentage, such that there is an 80 percent level of certainty.

Item / Description	OPCC (October $2016)	OPCC (July $2019)
Penstocks (3)	$35,000,000	$38,000,000
Draft Tube Tunnels (3)	$15,000,000	$16,000,000
Draft Tube Gate and Transformer Gallery	$20,000,000	$22,000,000
Draft Tube Gates and Shafts (3)	$19,000,000	$21,000,000
Tailrace Tunnel	$27,000,000	$30,000,000
Lower Reservoir I/O Structure and Channel	$30,000,000	$33,000,000
Surge Chambers	Assumed Not Required	Assumed Not Required
Powerhouse E/M Equipment	$850,000,000	$931,000,000
Powerhouse Main Access Tunnel	$20,000,000	$22,000,000
Powerhouse High Voltage Tunnel	$20,000,000	$22,000,000
Miscellaneous Portal Facilities	$5,000,000	$5,000,000
Underground Excavation Haul Tunnels	$15,000,000	$16,000,000
Substation and Switchyard	$30,000,000	$33,000,000
Transmission and Interconnect	Not included	Not included
Roads, Road Maintenance and Miscellaneous Yards	$25,000,000	$27,000,000
Lands	Not included	Not included
Temp Facilities, Site Prep, Mobilization/Demobilization	$50,000,000	$55,000,000
Contractor Bonds, Insurance, Taxes, and Profit (15%)	$279,915,000	$307,000,000
Environmental Measures (see Table 1-2)	$25,270,000	$25,270,000
Subtotal Direct Construction OPCC	$2,158,360,000	$2,363,345,000
Owner's Indirect Costs (20%)	$431,672,000	$472,669,000
Total Construction Direct and Indirect OPCC	$2,590,032,000	$2,836,014,000
Estimated OPCC $/MW	$2,158,360.00	$2,363,345.00

Source: HDR 2017

E/M = electro-mechanical; MW = megawatt; MWh = megawatt-hour; OPCC = Opinion of Probable Cost of Construction; USBR = United States Bureau of Reclamation; CCT = Construction Cost Trends

[a] Costs represent an Association for the Advancement of Cost Engineering Class 5 cost estimate.

[b] 2019 cost opinion based on escalation of 2016 costs using United States Bureau of Reclamation construction cost composite trend index.

Table 1-2: Proposed Environmental Measures and Estimated Costs

Resource Area	PM&E Measure Category	Task Description	Initial Cost	Incremental Cost	Frequency (years)	Total Cost
Water Resources	Hazardous Substances Spill Prevention and Cleanup Plan	Develop and implement Plan	$20,000			$20,000
	Operational Adaptive Water Quality Monitoring and Management Program	Develop and implement Plan	$30,000	$2,000	45	$120,000
	National Pollutant Discharge Elimination System permit	Apply for permit (construction activities)	$10,000			$10,000
	Stormwater Pollution and Prevention Plan	Develop and implement Plan	$20,000			$20,000
Wildlife Resources	General wildlife protection	Environmental Training Program (and manual) for employees	$10,000			$10,000
		Construction biological monitoring	$208,000			$208,000
		Dust palliatives	$20,000			$20,000
		Weed control	See Vegetation Management and Monitoring Plan, cost to be determined			
		Reduce wildlife attractants to reservoirs (e.g., deterrents, shoreline management).	To be determined			
		Ongoing consultation during construction	$5,000			$5,000
		Reservoir monitoring of bird and mammal use	$5,000	$5,000	45	$230,000
		Fencing around reservoirs	$250,000			$250,000
		Shade balls	$12,000,000	$15,000	45	$12,675,000
		Develop and implement Plan	$20,000			$20,000
	Raptor protection	Raptor-safe transmission line construction measures	Included in construction costs			
	Raptor protection	Three pedestrian pre-construction raptor nest survey/monitoring events	$40,000			$40,000

Resource Area	PM&E Measure Category	Task Description	Initial Cost	Incremental Cost	Frequency (years)	Total Cost
	Migratory bird protection	Migratory bird risk assessment literature review	$10,000			$10,000
	Avian protection (migratory and nocturnal birds)	Manage light pollution by installing specific types of lighting and mitigation measures	Included in construction costs			
	Scavenger protection	Carcass removal program during operations	$5,000	$5,000	45	$230,000
Recreation	Interpretive sign and access	Develop and install a handicapped accessible interpretive sign	$7,000			$7,000
	Visual and Recreation Resources Management Plan	Develop and implement Plan	$20,000			$20,000
Cultural	Historic Properties Management Plan	Implement Plan	To be determined			
	Tribal consultation	Continued tribal consultation	To be determined			
Geology & Soils	Soil Erosion Control Plan	Develop and implement plan	$75,000			$75,000
	Soil and groundwater protection	Cleanup of WSI	$10,100,000			$10,100,000
		New Groundwater Wells around WSI	$550,000			$550,000
		Hazardous Substances Spill Prevention and Cleanup Plan	See Hazardous Substances Spill Prevention and Cleanup Plan. To be determined.			
Botanical	Sensitive plant protection	Pre-construction sensitive plant surveys	$30,000			$30,000
	Weed management	Pre-construction invasive plant surveys	$30,000			$30,000
		Develop weed control plan	$10,000			$10,000
		Weed control implementation	$30,000	5000	45	$255,000
	General vegetation management and protection	Environmental Training Program (and manual) for employees	See cost under Wildlife			
	Revegetation	Revegetation [a]	$150,000			$150,000

Resource Area	PM&E Measure Category	Task Description	Initial Cost	Incremental Cost	Frequency (years)	Total Cost
		Revegetation monitoring and maintenance [a]		30,000	5	$150,000
	General vegetation management and protection	Vegetation management summary reports		5,000	5	$25,000
Aesthetics	Fish and aquatic protection	Revegetation (as erosion control BMP)	See cost under Botanical			
		Use sediment and erosion control BMPs near the waterbodies (ponds, intermittent/ephemeral channels)	See Sediment and Erosion Control Plan			
		Water quality protection measures	See Sediment and Erosion Control Plan and Stormwater Pollution and Prevention Plan			
	Manage light pollution	Install specific types of lighting and mitigation measures to minimize light pollution	Included in construction costs			
		Total Environmental Measures				$25,270,000

BMP = best management practice; PM&E = protection, mitigation, and enhancement; WSI = West Surface Impoundment

[a] Costs and duration contingent upon success of initial reseeding and weed control efforts.

2.0 EXISTING STRUCTURE AND FACILITIES

There are no existing structures or facilities at this site.

3.0 RESIDUAL VALUE AFTER LICENSE EXPIRATION

Many components of the Project will have a useful life beyond the expiration of the license, and this is particularly true of the major civil works. The net investment for the Project is estimated at $0, as it will have generated enough depreciation and revenue in its life to eliminate any residual investment value. It is possible that some late-stage equipment failure may require new investment in the later years of the license that may not be fully depreciated. The Project is considered unique and is interconnecting at a critical infrastructure location in the west; therefore, market valuation of the Project will likely be higher than the minimum fair valuation.

4.0 AVERAGE ANNUAL COST

Table 4-1 contains the average annual costs of the project. The costs of operations and maintenance (O&M) for environmental measures are specified in Table 1-2 and included in total costs in Table 4-1. All costs shown in the table are a 45-year average annual cost proxy, including cost escalation.

Environmental measures not included in the O&M costs listed in Table 4-1 are measures that will be enacted during construction (and therefore are a one-time cost) and for a specified short period after construction, not for the life of the Project. An example of these are activities such as revegetation of areas disturbed during construction, which are not included below. The O&M costs shown in Table 4-1 are for the first year of operation; after the first year, an escalation rate of 2.5 percent was assumed for all annual costs.

Table 4-1: Average Annual Cost from Completion of Project Construction to Expiration of Original License

Annual Cost Items	45 Year Average Annual Cost
Depreciation	$62,964,0000
Average annual taxes (income and property)	$115,620,000
Average operation and maintenance	$31,362,000
Operation and maintenance mitigation and environmental measures	$42,000
Energy pumping charge	$68,808,000
Total average cost	$278,796,000

5.0 ESTIMATED ANNUAL VALUE OF PROJECT POWER

The Pacific Northwest region’s energy market is expected to have a strong demand for peak capacity by 2028. Gas and/or oil generation facilities are not an option primarily due to the environmental constraints in the region combined with the strong regulatory push towards green power. Without gas or oil, batteries and pumped storage remain the viable alternatives. The unit cost of battery power is expected to be between $180 megawatt-hours (MWh) to $250 MWh. Based on the Project economics, the Applicant is expecting to sell capacity on long-term contracts to utilities in the region between $250 kilowatts per year to $275 kilowatts per year. This translates to approximately $85 MWh to $95 MWh, which is very competitive as compared to the expected battery power prices. In addition, the 1,200-megawatt Project provides the scale the utilities are looking for in the region. The facility will also be able to send and receive power to the southern California and Nevada market via the direct current Intertie, allowing the utilities to optimize capacity in two major power markets on the west coast, Mid-C and SP-15. The Applicant's expected annual revenues are $300 million to $330 million based on an expected approximately 34 percent capacity factor that will bring around a total of 3,561,000 MWh per year into these two markets.

On March 12, 2020, American Rivers, Friends of the White Salmon River, and the Washington State Chapter of the Sierra Club submitted comments to FERC regarding the Project. As part of these comments, the organizations attached a report by Rocky Mountain Econometrics (RME) purporting to evaluate the financial viability of the Project (RME 2019). In this report, RME concludes, "[i]t is also extremely unlikely that the Project will be financially viable," and provides several flawed comments throughout the report (RME 2019).

RME's critiques within their 2019 report are based on a misunderstanding of (1) wholesale electricity markets, (2) the expected evolution of electricity markets in response to clean energy policy, and (3) the operational capabilities and economic value streams provided by pumped storage. The RME study failed to mention the policy-driven evolution of the electricity market in the Pacific Northwest, which has been underway for nearly a decade now. We respond to RME's critiques in Attachment 1 of this exhibit by first summarizing how clean energy legislation in the Pacific Northwest drives the need for long-duration energy storage resources, and then providing detailed responses to claims made by RME.

6.0 OTHER ENERGY ALTERNATIVES

Other energy alternatives are available in the Pacific Northwest region; however, popular demand does not indicate support for large-scale construction of new gas, oil, coal, or nuclear-fueled power plants, and Washington state policy does not support fossil fuel development. Renewable energy projects such as wind and solar are not a good comparison to the Project for several reasons. First, wind and solar projects are non-dispatchable and are unable to provide capacity and ancillary services to the market. Second, the influence of renewable portfolio standards, which are mandated for renewable technologies, distorts the supply/demand balance—and therefore the cost—of these generators. Third, the influence of federal and state tax incentives in the form of tax credits, either production-based or investment-based, distort the true costs of these generators.

California and the Pacific Northwest region are pursuing aggressive strategies to reduce greenhouse gas emissions from electricity production, primarily through the planned retirement of existing coal-fired power plants. As a result, it is estimated that as much as 10,500 MW of fossil-fuel generation capacity could come offline by 2030, prompting concerns among regulators and utilities regarding resource adequacy during key hours.

Meanwhile, the Pacific Northwest region is poised to add substantial volumes of wind and solar energy over the coming decade, though the effective capacity values of such resources are relatively small in comparison to those of the retiring coal units. The successful integration of large amounts of wind and solar power will depend on highly flexible, economical bulk energy storage that can respond to long-duration, intra-day ramping needs to maintain reliability and avoid wind and solar energy curtailment during light load periods.

Pumped hydro storage is the only asset that provides large-scale, cost-effective renewable energy storage capacity and a range of essential grid reliability services, the value of which will increase as penetration of intermittent renewable resources rises (Navigant 2019). Pumped storage is increasingly compared and contrasted with Lithium Ion (Li-ion) batteries. In general, Li-ion batteries have excellent energy and power densities and round-trip efficiency. However, the average duration of Li-ion batteries is 4 hours, which limits their ability to support the integration of high percentages of renewable energy. A more thorough exploration of this issue is presented in a white paper entitled *What Is Driving Demand for Long Duration Energy Storage?* (Navigant 2019). The relatively short cycle life of Li-ion batteries, which can range from 500 to 10,000 cycles depending on usage and the specific Li-ion chemistry used, translates into a 3- to 15-year lifespan. This makes Li-ion batteries an expensive choice for long-term grid applications (Navigant 2019).

7.0 CONSEQUENCES OF DENIAL OF LICENSE

If FERC staff determines that a license should not be issued for the Project, the following value creations of the Project would be lost to residents and ratepayers in Washington and Oregon:

- Creation of low carbon and low-cost energy during peak use periods;
- Provision of ancillary services to respond to immediate needs of ramping and load following;
- Provision of regulation to manage grid stability, in particular with relation to renewable generation;
- Ability to absorb surplus renewable energy or other forms of energy such as traditional hydropower when there is surplus generation allowing the resource to not be curtailed or for hydro to not spill water; and
- A marked reduction in carbon dioxide from fossil fuel generators.

If a license is not issued for the Project, it is expected that the site would be redeveloped for an alternative commercial use.

8.0 PROJECT FINANCING

The Project could be completely balance-sheet financed by National Grid or be constructed with long-term debt financing.

9.0 PROJECT LICENSING COST

The Applicant estimates total licensing costs to be approximately $7 million.

10.0 MARKET PRICE ESTIMATE

The future value of revenues and costs associated with operating the Project are based on market comparisons and expected demand for peak capacity, and have been described in earlier sections of this exhibit—the costs are presented in Section 4.0, and the market prices and revenues are presented in Section 5.0.

11.0 REFERENCES

HDR. 2017. *JD Pool Pumped Storage Hydropower Project, Conceptual Study*. June 9, 2017.

Navigant Research. 2019. *What is Driving Demand for Long Duration Energy Storage?* White Paper. Published 2Q. Accessed December 2019. https://www.slenergystorage.com/documents/20190528_Webinar_White_Paper.pdf

RME (Rocky Mountain Econometrics). 2019. *Critique of the Goldendale Energy Storage Hydroelectric Project (FERC No. 14861) Notification of Intent*. December 3. Prepared for American Rivers.

ATTACHMENT 1:

RESPONSE TO THE ROCKY MOUNTAIN ECONOMETRICS "CRITIQUE OF THE GOLDENDALE ENERGY STORAGE HYDROELECTRIC PROJECT (FERC NO. 14861) NOTIFICATION OF INTENT"

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Acronyms and Abbreviations

CAISO	California Independent System Operator
FERC	Federal Energy Regulatory Commission
IMM	independent market monitor
kW	kilowatt
LSE	load-serving entity
MMBtu	million British Thermal Units
MW	megawatt
MWh	megawatt-hour
Net CONE	net cost of new entry
O&M	operations and maintenance
PGE	Portland General Electric
Project	Goldendale Energy Storage Project No. 14861
PV	Photovoltaic
RME	Rocky Mountain Econometrics

1.0 INTRODUCTION

On March 12, 2020, American Rivers, Friends of the White Salmon River, and the Washington State Chapter of the Sierra Club submitted comments to Federal Energy Regulatory Commission (FERC) regarding the Goldendale Energy Storage Project No. 14861(Project). As part of these comments, the organizations attached a report by Rocky Mountain Econometrics (RME) purporting to evaluate the financial viability of the Project (RME 2019). In this report, RME concludes, "[i]t is also extremely unlikely that the Project will be financially viable," and provides several flawed comments throughout the report (RME 2019).

RME's critiques within their 2019 report are based on a misunderstanding of (1) wholesale electricity markets, (2) the expected evolution of electricity markets in response to clean energy policy, and (3) the operational capabilities and economic value streams provided by pumped storage. The RME study failed to mention the policy-driven evolution of the electricity market in the Pacific Northwest, which has been underway for nearly a decade now. We respond to RME's critiques here by first summarizing how clean energy legislation in the Pacific Northwest drives the need for long-duration energy storage resources, and then providing detailed responses to claims made by RME.

2.0 POLICY CONTEXT AND LOW-CARBON ELECTRICITY SYSTEMS

The electric power sector across the western United States is undergoing significant changes in response to new policy and technology. In the Pacific Northwest, decarbonization of the electric sector has been driven by state-level clean energy policy, including (1) the Clean Energy Transformation Act in Washington State, which eliminates coal-fired electricity by 2025 and requires 100 percent clean electricity supply by 2045, and (2) the Oregon Clean Electricity and Coal Transition Plan, which removes coal-fired electricity generation from the state's electricity supply by 2035 and increases the renewable portfolio standard to 50 percent by 2040.[1]

To meet the policy objectives of electricity decarbonization, there has been a large investment in renewables. However, shifting towards a renewables-heavy (hydro, wind, and solar) electricity system introduces significant supply-demand dynamics for all timescales (e.g., minute to minute; hour to hour; season to season). The principal challenge of achieving a low-carbon grid is managing energy imbalances where energy surpluses (i.e., where generation exceeds load) and energy deficits (i.e., where load exceeds generation) persist over long timescales (e.g., seasons) (Jones et al. 2018).

The Pacific Northwest's hydro-dominated system is already accustomed to managing seasonal energy imbalances, particularly during the spring runoff when hydro generation peaks and loads

[1] Idaho Power, a utility that serves nearly 560,000 customers, has set a goal for 100 percent clean energy by 2045 (Idaho Power 2019).

are low. One of the primary motivations for developing the interties between California and the Pacific Northwest was to sell surplus Pacific Northwest hydro to California in the spring and early summer, and exporting power from California to the Pacific Northwest during the winter when the region's loads peak (Northwest Power and Conservation Council Undated). The growth of wind power plants in the Columbia River Gorge has already exacerbated this challenge, and the Bonneville Power Administration has curtailed wind generation when hydrogeneration was above average, load was low, and other balancing solutions were not available (EIA 2011).

Seasonal energy imbalances will occur more frequently as the electric sector is decarbonized, and even though the region has been able to use its interties to help manage energy imbalances in the past, clean energy policy in other jurisdictions will pose new challenges. For example, California's goal of 100 percent clean electricity supply by 2045, which is largely expected to be met by solar, will result in energy surpluses during the spring that reduce the need for imports from the Northwest. These factors will drive a need for balancing resources in the northwest that can shift substantial energy from periods of surplus to deficit. Long-duration energy storage, such as Goldendale, fit this criterion.

Western wholesale energy markets are being profoundly affected by clean energy policy and increasing volumes of renewable electricity. Today, energy prices largely reflect the efficiency of the marginal gas-fired resource and the natural gas price. In a decarbonized future, supply in energy markets will primarily come from resources that are non-dispatchable and have near-zero marginal costs, which will (1) decrease energy prices on average and be near-zero in most hours; (2) increase energy prices during hours of challenging system conditions, such as high loads and low renewable output; and (3) increase price volatility.[2] As a result of these changes, the historical (2014 to 2018) wholesale energy prices applied by RME are fundamentally flawed and do not reflect the market environment that Goldendale will operate in. What makes RME's flaws so concerning is that the market changes ignored by RME have been the focus of analysis and debate amongst regional utilities, legislators, and other non-governmental organizations for the better half of the last decade.

3.0 RME'S CRITIQUE OF GOLDENDALE'S FINANCIAL VIABILITY

RME claims that the Goldendale Project is, "…very unlikely to operate profitably given the state of current and future west coast and northwest energy pricing" (RME 2019). RME's conclusion about the financial viability of Goldendale is flawed because it (1) excludes sources of economic value that long-duration energy storage projects provide, and (2) underestimates energy value by misusing historical wholesale energy prices.

[2] These changes have been already been observed in markets with increasing renewable penetrations (Joskow 2019).

3.1 Financial Assessments Do Not Account for the Full Value of Long-Duration Storage

Energy storage resources provide a variety of economic value to bulk power systems. In a low-carbon and renewable-heavy electricity system, value is concentrated in the categories listed in Table 5.1-1.

Table 5.1-1: Long-Duration Storage Value Steams

Category	Description
Energy Value	Storage facilities charge when energy prices or the marginal cost of generation is relatively low and discharge when energy prices are relatively high or marginal system costs are expensive. This is commonly referred to as energy arbitrage.
Capacity Value	Storage can provide system capacity that contributes towards resource adequacy and avoids investment in alternative capacity resources.
Flexibility Value	The operational flexibility of storage allows it to provide a variety of ancillary services, including operating reserves such as regulation and contingency (spin and supplemental/non-spinning) reserves. Furthermore, storage can provide load following reserves to address sub-hourly net load variations.
Avoided Renewable Curtailment	Storage has value by mitigating curtailment of renewable generation and avoiding investment in alternative balancing solutions.

RME's estimate of Goldendale's revenues are limited to energy value and exclude capacity value and flexibility value, and avoid renewable curtailment. In addition, energy value is underestimated, which we describe in detail in Section 3.2 below. The missing attributes represent significant economic value to Goldendale and are accounted for in standard electric power industry assessments, such as utility integrated resource planning.

3.1.1 Capacity Value

Capacity value represents the economic value of a resource contributing towards resource adequacy requirements. This is the marginal cost of capacity and, in most electricity markets, is estimated as the net cost of new entry (Net CONE) of a new gas-fired resource. Net CONE is the levelized fixed cost (capital and fixed operations and maintenance [O&M]) of a new gas plant minus net revenues from participating in energy and ancillary services markets.

To illustrate the magnitude of capacity value to a load-serving entity (LSE), we present the annualized fixed cost and net energy revenues for a new gas combined cycle plant located in Northern California (NP15) in 2018. NP15 is presented to match the wholesale energy market prices used by RME. California Independent System Operator's (CAISO) independent market monitor (IMM) estimates a new gas combined cycle plant has an annualized fixed cost of $145/kW-year and would earn net energy revenues between $33.4/kW-year and $43.3/kW-year in 2018.[3] This results in a capacity value ranging from $102/kW-year to $112/kW-year.[4] Furthermore, Portland General Electric (PGE) estimates a capacity value of a new gas combustion turbine plant of $103/kW-year in its 2019 Integrated Resource Plan (Section 6.2.3 of PGE 2019).

Capacity value would represent a significant source of revenue to Goldendale. To illustrate this point, if we assume a range of $90 to $110/kW-year for capacity payments, then this would provide between $108 to $132 million per year in revenue. In the northwest, new capacity is needed in the near-term to address resource adequacy requirements driven by load growth and coal-fired resource retirements. The Northwest Power and Conservation Council projects the region will have insufficient resources by 2021 (Northwest Power and Conservation Council 2018), and the Northwest Power Pool expects, mid-2020s, the region may face a capacity deficit of thousands of megawatts" (Northwest Power Pool 2019). Long-duration storage resources are ideal to meet new capacity needs in the Northwest, because they're consistent with long-term policy goals requiring a LSE to meet all or a substantial portion of load with clean energy. Additionally, Goldendale's location could allow it to provide capacity in California through Pacific Direct Current Intertie.

The need for new capacity with low-carbon attributes is already reflected in electric utility Integrated Resource Plans. For example, Avista's preferred resource strategy from its 2020 Integrated Resource Plan includes 175 MW of long-duration storage by 2026,[5] and PGE's preferred portfolio from its 2019 Integrated Resource Plan includes 200 megawatts (MW) of pumped storage by 2024.[6]

3.1.2 Flexibility Value

In addition to planning reserves to meet long-term reliability requirements (e.g., resource adequacy), balancing authorities must ensure reserves on shorter timescales to meet operational reliability. Operating reserves allow balancing authorities to respond to imbalances due to the variability and uncertainty of load and generation. Higher renewable penetrations further increase the variability and uncertainty of net load (load minus non-dispatchable generation) and increase reserve requirements. Systems have already implemented or contemplated additional reserve products, such as load-following or flexibility reserves, and revised ancillary services markets.[7]

[3] Table 1.4 and Table 1.5 from CAISO 2018
[4] The CAISO 2018 annual report notes that since energy market revenues are significantly below annualized fixed costs, "[t]his underscores the need for new resources necessary for reliability to recover additional costs from long-term bilateral contracts" (CAISO 2018).
[5] Table 1.1 in Avista 2020
[6] Table ES-5 in PGE 2019
[7] For example, CAISO implemented flexible capacity requirements (CAISO 2020a).

Today, thermal and hydro resources supply most reserves, but thermal plants burn fuel and emit while online and hydro reserve provision is limited by non-power constraints. Pumped storage's operational capabilities allow the resource to meet growing reserve requirements in both pumping and generating modes (Argonne National Laboratory 2014). The flexibility value of pumped storage represents multiple services ranging from regulation to load-following, and overall value will vary substantially due to (1) system characteristics (e.g., thermal- versus hydro-dominant; variability of load shape), (2) renewable share of generation, and (3) assumed reserved products included in flexibility value. In addition, the Pacific Northwest does not have a centralized ancillary services market like CAISO, and ancillary services prices are procured by each individual balancing authority.

For reference, we present estimated value for pumped storage from three northwest utilities: (1) Avista estimates an "ancillary services" value of $4.93/kW-year; (2) PGE estimates "flexibility value" of $25.95/kW-year; and (3) Puget Sound Energy estimates "flexibility cost savings" of $10.24/kW-year.[8] Overall flexibility value is expected to be smaller than capacity value, but it represents an important revenue stream for long-duration storage resources.

3.1.3 Renewable Curtailment Value

At high renewable penetrations, curtailment of renewable generation is frequent in the absence of balancing solutions. In the short-run, curtailment may be reflected in energy value through zero or negative energy prices when renewable plants are dispatched down. However, in the long-run, excessive renewable curtailment must be addressed to comply with policy.[9]

For example, consider an LSE that must meet all of its load with clean energy thatcontracted with a solar photovoltaic (PV) resource for $30.0/MWh with an expected (i.e., zero curtailment) capacity factor of 25 percent. The LSE experiences excess energy during period A (e.g., daylight hours) and a clean energy shortage during period B (e.g., morning and evening shoulder hours). Initially, the lack of flexibility on the LSE's system results in the solar PV plant curtailing 20 percent of its generation, which (1) reduces the effective capacity factor to 20 percent, (2) increases the Power Purchase Agreement cost to $37.5/MWh, and (3) decreases energy prices to zero during curtailment hours. The LSE could utilize pumped storage to charge during period A, generate during period B, and fully comply with its clean energy obligations. This avoids the need to invest in alternative balancing solutions, such as another renewable Power Purchase Agreement (e.g., wind plant), clean energy market purchases, battery energy storage, or transmission.

[8] Table 9.10 in Avista 2020; Table 6-5 in PGE 2019; Slide 48 in Puget Sound Energy 2019

[9] Some level of curtailment is economic.

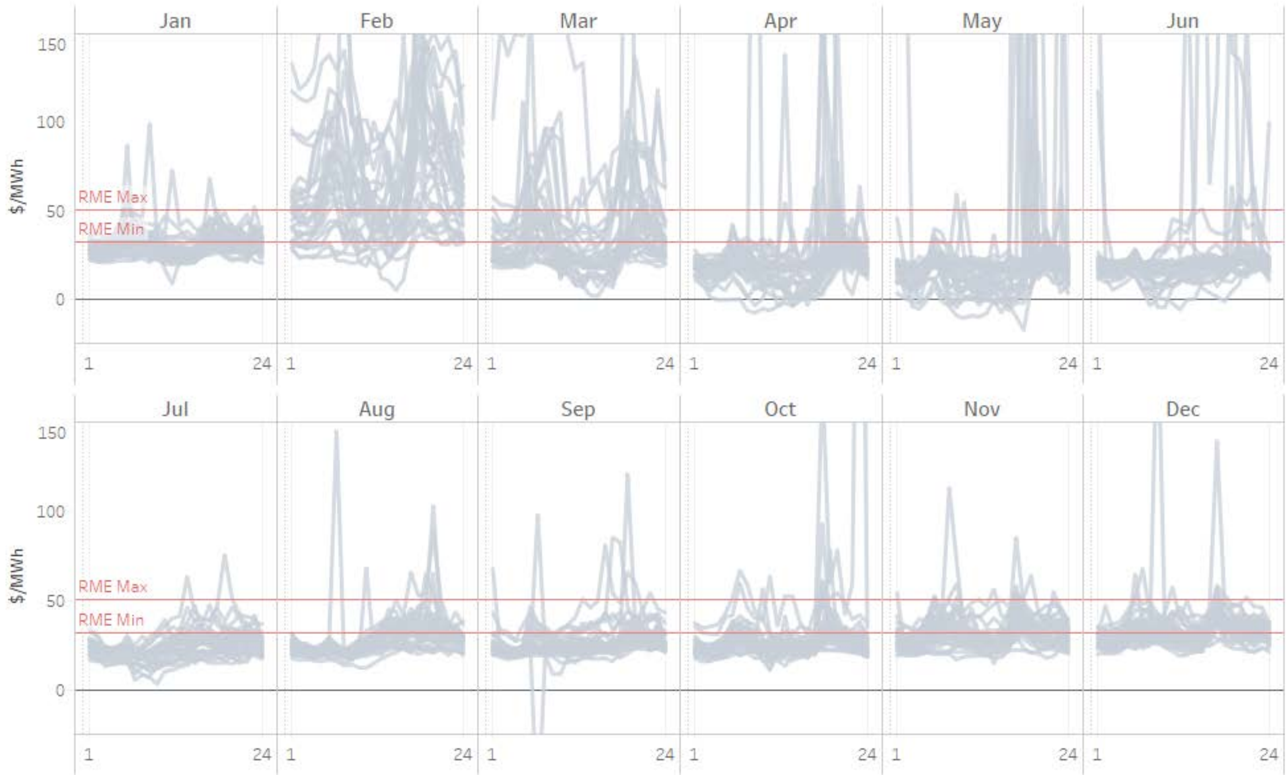
3.2 Energy Value is Substantially Underestimated

RME's calculation of Goldendale's net energy revenues from operating in a wholesale energy market substantially underestimate its true energy value. The miscalculations are two-fold: (1) historical wholesale energy prices are inappropriately applied, and (2) the operational capabilities of Goldendale are mischaracterized. In summary, RME's energy value calculation assumes (1) pumping for 10 hours per day at a price of $32/MWh, and (2) generating for 8 hours per day at a price of $50/MWh. As we explain below, this simple price-times-quantity metric ignores the realities of wholesale energy markets and Goldendale's operational capabilities.

3.2.1 Historical Wholesale Energy Market Prices

RME relies on historical NP15 prices from 2014 through 2018 to provide price signals for Goldendale's pumping and generation. Instead of relying on an hourly energy price stream, RME estimates an average minimum of $32.0475/MWh and an average maximum of $50.23530/MWh. We outline the broad issues with this approach.

First, using average prices dilutes historical wholesale energy price volatility, which drives Goldendale and any energy storage resource's energy value. To illustrate existing price volatility in wholesale energy markets, Figure 5.1-1 shows hourly locational marginal prices for the PacifiCorp West balancing authority area in 2019 plotted against RME's assumed minimum and maximum prices in red (CAISO 2020b). PacifiCorp West was selected to more accurately represent the physical location of Goldendale and PacifiCorp's participation in the CAISO Energy Imbalance Market provides hourly (8760) data. Prices are frequently below RME's average minimum in all months and near-zero in the spring when hydro, wind, and solar generation are highest. These hours present opportunities to pump at more favorable costs than RME assumes. Prices exceed RME's average maximum threshold frequently in the early evening and morning, which allows for economic generation opportunities.



Source: CAISO 2020b

Figure 5-1: PacifiCorp West Locational Marginal Prices (2019)

To further illustrate what RME's average minimum and average maximum prices represent, we convert the energy price into a market heat rate (in million British Thermal Units [MMBtu] per MWh). Market heat rates are calculated by subtracting the variable O&M cost from the energy price and then dividing by the price of natural gas and greenhouse gas allowance cost.[10] This metric approximates the average efficiency of the marginal unit setting the wholesale energy price. As shown in Table 5.1-2, the market heat rate of the average minimum is 7.1 MMBtu/MWh, which is the efficiency of a gas-fired combined cycle plant, while the market heat rate for the average maximum is 11.5 MMBtu/MWh, which is the efficiency of a gas-fired combustion turbine or steam turbine peaking plant. RME is implicitly assuming Goldendale is pumping with electricity produced by a gas-fired combined cycle resource and discharging to avoid generation from a less efficient gas plant. This gas-on-gas arbitrage is a relic of averaging historical hourly prices, and ignores one of the primary purposes of Goldendale, which is to pump using renewable electricity generation (i.e., market heat rate near zero) and deliver emissions reductions.

[10] This follows the same approach used by CAISO in Section 2.3 of their 2018 annual report (CAISO 2018).

Table 5.1-2. Market Heat Rates of RME Energy Prices

Component		Average Minimum	Average Maximum	Source and Notes
Energy Price	$/MWh	$32.05	$50.25	RME 2019 (within this report, RME used the 2014 through 2018 minimum and maximum prices)
Variable O&M	$/MWh	$2.80	$2.80	CAISO 2018, Section 2.3
Natural Gas Price	$/MMBtu	$3.42	$3.42	Average price at PGE Citygate from 2014 through 2018
Greenhouse Gas Price	$/MMBtu	$0.69	$0.69	Average California Air Resources Board auction price from 2014 through 2018
Market Heat Rate	MMBtu/MWh	7.1	11.5	

MMBtu = million British Thermal Units; MWh = megawatt-hour; O&M = operations and maintenance

Second, as we discussed above, hourly wholesale energy prices are projected to evolve in response to a changing resource mix. Since most generation resources will be non-dispatchable and have near-zero marginal costs, wholesale energy markets will see (1) energy prices decrease on average and be near-zero in most hours, (2) an increase in energy prices during hours of challenging system conditions, and (3) an overall increase in price volatility.

This viewpoint is shared across a wide spectrum including researchers and electric utilities. For example, Lawrence Berkeley National Laboratory assessed wholesale electricity markets with wind and solar penetrations of 40 to 50 percent and concluded:

> "We find a general decrease in average annual hourly wholesale energy prices with more VRE [variable renewable energy] penetration, increased price volatility and frequency of very low-priced hours, and changing diurnal price patterns. Ancillary service prices rise substantially and peak net-load hours with high capacity value are shifted increasingly into the evening, particularly for high solar futures." (LBNL 2018)

Furthermore, PGE notes in its Integrated Resource Plan (PGE 2019):

> "The combination of expanded solar and wind deployment with ongoing thermal plant retirements creates the potential for price volatility and uncertainty in the West, with low or negative pricing during hours with high renewable output and very high pricing during hours with high load and supply constraints."

This broad agreement contradicts RME's claim that "…the wholesale energy environment in which it will operate are clear" (RME 2019).

Finally, it is inappropriate to use historical prices from a limited period to value a long-lived asset (e.g., 40+ years of operation). The historical period of 2014 through 2018 represents short-run conditions and does not represent long-run equilibrium prices to support investment to maintain reliability and meet policy goals. Entities that evaluate new generation resources, such as electric utility integrated resource planning processes and the Northwest Power Planning

Council's Power Plan, continually refresh their forward-looking analyses to include changes to policy and technology costs rather than rely on historical prices to represent the future. These analyses were publicly available at the time of RME's assessment.

3.2.2 Pumped Storage Operational Capabilities

RME's estimate of net energy market revenues is exacerbated by assuming that Goldendale will follow a fixed pattern of operations, including (1) pumping for 10 hours per day, (2) generating for 8 hours per day, and (3) standby for 6 hours per day.[11] Pumping and generation modes occur at Goldendale's full nameplate capacity (i.e., 1,200 MW). Assuming an operations schedule for every day ignores the inherent flexibility of Goldendale and its ability to respond to changing load and supply conditions both in the Pacific Northwest and California. For example, assuming 14,745 MWh of energy storage (~12 hours), Goldendale could operate in the following ways:

- Only pump throughout the course of day and then generate the next day or weeks later;
- Only generate throughout the course of the day for 12 hours at 1,200 MW output, or 18 hours at 800 MW output, etc.; and
- Generate with one unit (400 MW) and provide reserves with the other units (800 MW).

In summary, there are many ways that Goldendale could be dispatched, and in reality will be optimized in response to wholesale energy and ancillary services price signals or contractual obligations rather than a diurnal pattern that is more likely for a short-duration storage resource.

4.0 OTHER RME CRITIQUES

Section V, General Discussion, of the RME 2019 report includes multiple inaccurate claims about Goldendale and power system operations. We provide responses to individual points below.

4.1 Large Producer

"Unlike many hydro type power producers that typically only run at full capacity during spring runoff or brief moments to match peaking demand, Goldendale can be expected to run at or near full capacity for most of its daily 8-hour operation as it attempts to maximize revenue."

As discussed above, Goldendale does not need to generate at its full capacity nor does it need to generate for 8 hours per day. Instead, the Project will optimize its dispatch based on price signals or manage its state-of-charge.

[11] The rationale for implicitly assuming standby for 6 hours per day is unclear.

4.2 Net Consumer of Electricity

"The result is that to produce 3.5 million MWh of electricity Goldendale will consume about 4.4 million MWh, an annual loss to the system of about 877,000 MWh."

All generating resources have an efficiency less than 1.0 and produce losses, whether that is from fuel consumption or electricity usage. Despite being a net consumer of electricity, Goldendale will actually improve the efficiency of the bulk power system by flattening the net load curve.

4.3 General Operating Characteristics

"In the absence of high prices in the wholesale energy market, the alternative method for absorbing overhead is to operate as many hours per year as possible. That, combined with minimal marginal operating costs, is the reason most hydro facilities operate as close to 24/7 as possible."

Hydroelectric plants operate at 24/7 below their nameplate capacity and because of hydrologic conditions, not because of price signals.

4.4 "Quick Response" May Not Mean Lower Rates

"Responding to emergencies may be a benefit to the system but chasing momentary price changes can increase chaos, uncertain, and risk, and be detrimental to the system." and "Given Goldendale's precarious financial situation, and in the absence of regulatory or contractual operational constraints, increased wholesale market chaos appears to be the most likely result of Goldendale's operation."

Pumped storage resources have been operating in wholesale electricity markets across the United States for decades, including CAISO, PJM, NYISO, and ISO-NE. RME's claim that Goldendale will cause chaos is unfounded. In fact, system operators, including ISO-NE, disagree with RME's statement and find that pumped storage is one of the best tools to balance a system with intermittent sources of renewable energy. ISO-NE offered a letter of support of the operational benefits of the Bear Swamp pumped storage resource and noted that, "The Bear Swamp Project is a pumped storage hydropower facility that can be available to supplement the loss of production from 'just-in-time' resources when the weather is not cooperating" (ISO New England Inc. 2019).

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