PNNL-30225

Techno-economic Assessment for Generation III+ Small Modular Reactor Deployments in the Pacific Northwest

April 2021

Mark R. Weimar, Ali Zbib, Don Todd, PNNL;
Jacopo Buongiorno, Koroush Shirvan, MIT

Prepared for the U.S. Department of Energy
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Pacific Northwest National Laboratory
Richland, Washington 99354

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Abstract

Legislative changes in the Pacific Northwest (PNW), notably in Washington State, are driving the electricity sector to be carbon neutral by 2030 and ultimately carbon free by 2045. The legislative changes have renewed interest in nuclear power as a sustainable, carbon-free source of baseload electricity. The renewed interest aligns with the U.S. Department of Energy's objectives of restoring U.S. leadership in nuclear energy and accelerating the deployment of nuclear power plants, including small modular reactors (SMRs), in the United States. Thus, Pacific Northwest National Laboratory (PNNL) in collaboration with the Massachusetts Institute of Technology, conducted a study that evaluated siting Gen III+ SMR concepts in Washington State. The study evaluated the market changes in consideration of Washington State's legislation. The study included the integration of advanced reactor concepts in a clean energy portfolio. The legislative changes along with projected levelized costs of energy and the projected electricity market were analyzed to determine the feasibility of introducing SMRs to meet the goals of zero carbon emissions. Five case studies were analyzed combining two SMR technologies and three potential sites: The NuScale SMR was evaluated at three potential sites and the GEH BWRX-300 was evaluated at two potential sites. The first case study evaluated NuScale at the Idaho National Laboratory as a potential Utah Association of Municipal Power Systems project. Case 2 evaluated a NuScale SMR at the Energy Northwest site (Site 1) in eastern Washington State. The third case study evaluated placing a GEH BWRX-300 at Site 1 with the same cost reductions as the NuScale Plant. Cases 4 and 5 evaluated NuScale and an GEH BWRX-300, respectively, at the current Centralia coal plant site. Although Levelized Costs of Electricity (LCOEs) were developed for both NuScale and GEH, the sets of LCOEs are not comparable. NuScale's estimate is based on the current design. GEH is using a design-to-cost methodology with target pricing that is being confirmed as the design matures. The feasibility study indicated that in a future carbon-free electricity sector, deployment of advanced SMRs would be competitive if the projected LCOEs for these designs can be attained. An LCOE in the range of \$51/MWh–\$54/MWh was calculated for the NuScale design using NuScale's design estimates. An LCOE in the range of \$44–\$51/MWh was calculated for the BWRX-300 using GEH's design-to-cost and target pricing input.

Executive Summary

Legislative changes in the Pacific Northwest, notably in Washington State, are driving the electricity sector to be carbon neutral by 2030 and ultimately carbon free by 2045. The legislative changes have stimulated renewed interest in nuclear power as a sustainable, carbon-free source of firm, flexible electricity. The renewed interest aligns with the U.S. Department of Energy's objectives of restoring U.S. leadership in nuclear energy and accelerating the deployment of nuclear power plants including small modular reactors (SMRs) in the United States (U.S.). Thus, Pacific Northwest National Laboratory (PNNL) and the Massachusetts Institute of Technology (MIT) conducted a study that evaluated the value proposition of deploying Generation (Gen) III+ SMRs advanced reactor concepts in the Pacific Northwest.

The feasibility study indicated that in a future carbon-free electricity sector, deployment of advanced SMRs would be competitive if the projected LCOEs for these designs can be attained. An LCOE for an nth-of-a-kind (NOAK) SMR in the range of $51/MWh–$54/MWh was calculated for the NuScale design using NuScale's design estimates. An LCOE in the range of $44–$51/MWh was calculated for the BWRX-300 using GE-Hitachi's (GEH's) design-to-cost and target pricing input. All results are in 2019$ with the exception of Utah Association of Municipal Power Systems' (UAMPS') price of $55/MWh, which is in 2018$. The NuScale and GEH BWRX-300 LCOEs are not intended to be directly compared in this study. NuScale's estimate is based on the current design. GEH is using a design-to-cost methodology with target pricing that is being confirmed as the design matures. Whether there needs to be a subsidy for the NOAK plant to enter the market depends on the price and quantity of competing resources, the size of the future market, the quantity of non-emitting resources that need to be replaced, and whether the UAMPS subscription price indicates that municipal utilities are willing to purchase firm electricity at $55/MWh. In addition, the quantity of future non-emitting capacity depends on the amount of emitting resources Washington utilities must replace, the availability and cost of unbundled renewable energy credits (RECs), and the quantity of energy conservation projects that have a positive net present value. Utilities can substitute up to 20 percent of the total sales with unbundled RECs and energy conservation projects through 2045.

A study of the Pacific Northwest electricity market showed significant variation in load on a monthly, daily and even 5-minute increment basis. An emerging clean energy market with a significant penetration of variable and intermittent renewable energy sources will require additional flexible power sources to address the load fluctuations. In addition to being a source of baseload power, these advanced nuclear reactor concepts are being designed with attributes that will address the characteristics of the emerging clean energy markets including flexible operation, black start capabilities, and island mode operation, which will help augment the variable and intermittent sources.

SMRs may face competition from other firm power sources. The Energy Information Administration (EIA) estimates geothermal entering the market in 2025 at $37/MWh (2019$), while advanced geothermal is estimated to cost $47/MWh (2019$). Entities can get a $2/MWh tax credit that reduces the cost to $35–$45/MWh if the project is properly structured. All estimates are probably in the same error range. Natural gas combined cycle (NGCC) power could be purchased between 2030 and 2045 at a penalty price of $97/MWh. These two resources bound the market for firm resources. If NGCC is required, no subsidy would be required because NGCC would set the market price. However, near-firm renewable resources could provide a portion of the energy required by the time the first SMR reaches commercial operation. Variable renewable resources with batteries or other storage could provide approximately 4 percent of the firm power requirements at current prices. According to two separate MIT studies, wind plus battery could provide between 16 and 95 percent of firm power requirements in the future at battery prices of about $150/MWh.

UAMPS suggested an exchange agreement with Bonneville Power Administration (BPA) to reduce current pancaking[1] transmission costs. With BPA's entry into the Energy Imbalance Market (EIM), a potential for a Western Electricity Coordinating Council (WECC) area-wide market, and assuming the potential one balancing authority like the Midwest Independent System Operator, the probability of having a larger wholesale power market increases. With a wider wholesale power market, energy could flow inexpensively from other EIM areas with an abundance of solar and wind at significantly reduced transmission costs. Only one transmission cost is applied rather than pancaking the transmission costs without the EIM and a wider wholesale market. One issue that will need to be understood is how the state of Washington will handle the mix of electricity coming over the transmission system, which will include carbon-emitting resources. The benefits of the EIM could be exemplified by the UAMPS shipping power to Washington State. The EIM reduces the overall transmission costs from Idaho to BPA from $24/MWh to $4/MWh.

The estimated market capacity derived from replacing carbon-emitting resources is about 5 GWe. With a growing population and increasing electric vehicle (EV) penetration, the capacity requirement could be larger. Near-firm production provides a narrow range for geothermal and SMRs to fill because near-firm generation could provide up to 5 GWe, which is the current coal and natural gas generating capacity in Washington State.

In a Day-Ahead Market like the California Independent System Operator's (CAISO's), the marginal cost of providing energy provides the supply curve for electricity delivery. As such, geothermal and SMRs would enter the market up to the quantity meeting their marginal costs. Everyone would receive the highest bid price. The price obviously does not cover long-run costs, but the expectation is that power shortages over time will provide prices high enough to cover the costs. In this scenario, no subsidy would be required. Under the current system each Balancing Area Authority is responsible for assuring their loads are balanced.

Bilateral agreements such as those occurring with UAMPS and subscribers to their plant are another approach to determining if a subsidy is required. Subscribers will purchase a mix of generation to meet their energy needs. If the UAMPS subscription target is an indicator, utilities appear to be willing to pay $55/MWh for firm power, which indicates that a subsidy in the range $15–$30/MWh is required for the first-of-a-kind (FOAK) plant depending on the assumptions used to derive the subsidy. This also suggests that if the price of the NOAK plant is below the $55/MWh target, utilities might not need any further subsidy for firm power. If the price for SMR electricity is higher, then a subsidy would be required to bring the cost down to the point where utilities would buy the power. In addition, if the project can be properly structured, the production tax credit could be potentially sold, which would provide an approximate $7/MWh subsidy according to EIA, This indicates that if both NuScale and GEH can reach their estimates for an NOAK plant they would need no additional subsidy.

Energy Northwest (ENW) is evaluating adding SMR capacity in Washington State. ENW, formerly the Washington Public Power Supply System, was formed in 1957 and has a history of providing nuclear power. It operates the Columbia Generating Station (CGS), a boiling water reactor (BWR) that is just north of Richland, Washington, on a site that includes another partially built nuclear power plant. The CGS produced power for $35.6/MWh and $47.6/MWh in fiscal year (FY) 2018 and FY 2019, respectively. The fluctuation depends on refueling outages and other activities (ENW 2019). The projected LCOE (2014–2043) is between $47/MWh and $52/MWh (ENW 2020). They are selling power at cost to the BPA.

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[1] Pancaking refers to each transmission owner adding their transmission costs to the Power Purchase Agreement price.

This study evaluated the market changes considering Washington State's legislation. The legislative changes along with projected LCOEs and the projected electricity market were analyzed to determine the feasibility of introducing Gen III+ SMRs to meet the goals of zero carbon emissions. Five cases studies were analyzed:

- The first case study evaluated a NuScale SMR at the Idaho National Laboratory (INL) site as a potential UAMPS project. The INL site is currently under development and UAMPS provided a Power Purchase Agreement (PPA) price and suggested a way to get the electricity to Washington State at lower costs.
- Case 2 evaluated a NuScale SMR at ENW's Site 1 in eastern Washington State. The site was previously evaluated for construction of a light water reactor (LWR) nuclear power plant. Cost reductions associated with leveraging the existing infrastructure and documentation on the site, the benefits of building the plant in proximity to an operating BWR (CGS), and the benefits of constructing a plant in an area that already has a skilled nuclear energy workforce were assessed.
- The third case study evaluated placing an GEH BWRX-300 at Site 1 with the same cost reductions as those of the NuScale plant.
- Cases 4 and 5 evaluated NuScale and an GEH BWRX-300, respectively, at the site of the current coal plant in Centralia, Washington.

As this report was being finalized, two awards for advanced reactor demonstrations were announced by the U.S. Department of Energy: TerraPower's Natrium reactor, a 345 MWe sodium-cooled fast reactor with a molten salt thermal energy storage that can flex the power output to 500 MWe, and X-Energy's Xe-100 reactor, a 320 MWe (4-80 MWe modules) high-temperature gas reactor. The impact of these projects on the future energy markets were not evaluated in this study.

Acronyms and Abbreviations

AAPS	Alternate AC Power Source
AC	alternating current
ADS	accelerator driven system
ARPA-E	Advanced Research Projects Agency–Energy
ASME	American Society of Mechanical Engineers
B&W	Babcock & Wilcox
BA	Balancing Authority
BAA	Balancing Authority Area
BPA	Bonneville Power Administration
BWR	boiling water reactor
CAISO	California Independent System Operator
CCS	carbon capture and sequestration
CETA	Clean Energy Transformation Act
CFPP	Carbon-Free Power Plant
CGS	Columbia Generating Station
CMSR	CUBE Molten Salt Reactor
DCA	Design Certification Application
DoD	U.S. Department of Defense
DOE	U.S. Department of Energy
E3	Energy + Environmental Economics
EEDB	Energy Economics Data Base
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIS	environmental impact statement
ENW	Energy Northwest
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPR	European Pressurized Reactor
EPRI	Electric Power Research Institute
EPZ	Emergency Protection Zone
ER	Environmental Report
EV	electric vehicle
FOAK	first-of-a-kind
FRP	full rate production
FTE	full-time equivalent (employee)
GEH	GE-Hitachi

GW	gigawatt
HFC	hydrofluorocarbon
HLH	High Load Hour
HX	heat exchanger
I&C	instrumentation and controls
IAEA	International Atomic Energy Agency
ICBM	Inter-Continental Ballistic Missile
ICS	isolation condenser system
INL	Idaho National Laboratory
IOU	investor-owned utility
IRR	internal rate of return
ITC	investment tax credit
kgHM	kilogram(s) heavy metals
kgIHM	kilogram(s) initial heavy metals
LCOE	levelized cost of electricity
LCOH	levelized cost of heat
LDV	light-duty vehicle
LEU	low-enriched uranium
LLH	Light Load Hour
LMP	Locational Marginal Price
LWR	light water reactor
MIT	Massachusetts Institute of Technology
MMBTU	million British thermal units
MW	megawatt(s)
MWh	megawatt-hour(s), unless otherwise stated, it is megawatt-hour electric
MWhe	Megawatt-hour(s) electric
MWht	megawatt-hour(s) thermal
NA	not available
NEI	Nuclear Energy Institute
NG	natural gas
NGCC	natural gas combined cycle
NGNP	Next Generation Nuclear Plant
NOAK	nth-of-a-kind
NPCC	Northwest Power and Conservation Council
NPM	nuclear power module
NPP	nuclear power plant
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory

NRIC	National Reactor Innovation Center
NW	northwest
O&M	operations and maintenance
ORNL	Oak Ridge National Laboratory
PAC	PacifiCorp
PCU	power conversion unit
PJM	Pennsylvania Jersey Maryland Independent System Operator
PNNL	Pacific Northwest National Laboratory
PPA	Power Purchase Agreement
PTC	production tax credit
PUD	Public Utility District
PWR	Pressurized Water Reactor
REC	Renewable Energy Credit
RPV	Reactor Pressure Vessel
SCO	Strategic Capabilities Office
SG	steam generator
SIE	South Idaho Exchange
SMR	Small modular reactors
SNF	Spent Nuclear Fuel
SSC	structures, systems, and components
SWU	Separative Work Unit
TE	Terrestrial Energy
TRL	Technology Readiness Level
TWR	Traveling wave reactor
UAMPS	Utah Association of Municipal Power Systems
U.S.	United States
USD	U.S. dollars
WA	Washington
WACC	weighted average cost of capital
WADOE	Washington Department of Ecology
WAPA	Western Area Power Administration
WEC	Westinghouse Electric Company
WECC	Western Electricity Coordinating Council
WLFR	Westinghouse Lead Fast Reactor
WNP-1	Potential SMR site north of Richland next to WNP-2; also called Site 1 in this report
WNP-2	Columbia Generating Station

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1.0 Introduction

Legislative changes in the Pacific Northwest, notably in Washington State, are driving the electricity sector to be carbon neutral by 2030 and ultimately carbon free by 2045. The legislative changes have prompted renewed interest in nuclear power as a sustainable, carbon-free source of baseload electricity. This renewed interest aligns with the U.S. Department of Energy's (DOE's) objectives of restoring U.S. leadership in nuclear energy and accelerating the deployment of flexible nuclear power plants, including small modular reactors (SMRs), in the United States (U.S.). Regionally, nuclear power may have an advantage over near-firm and firm renewables, because the renewable resource levelized cost of electricity (LCOE) differs from region to region. Thus, while small nuclear reactors may be too expensive in some regions, they may be cost competitive in others. To explore the implications for Washington State and its *Clean Energy Transformation Act* (CETA 2019), which commits the state to an electricity supply free of greenhouse gas emissions by 2045, Pacific Northwest National Laboratory (PNNL) in collaboration with Massachusetts Institute of Technology (MIT) conducted a study that evaluated the value proposition of deploying Generation (Gen) III+ SMRs in in the Pacific Northwest and Washington State.[1]

1.1 Study Purpose and Scope

The study reported here evaluated the market changes considering Washington State's legislation—CETA. The characteristics of SMRs were reviewed to evaluate their capability to meet flexibility requirements. The legislative changes along with projected LCOEs and the projected electricity market were analyzed to determine the feasibility of introducing SMRs to meet the zero carbon emission goals. Both near-term and long-term potential deployment options were assessed.

Five case studies were analyzed; near-term options included evaluating placement of NuScale-designed plants (each containing 12 SMR units) delivering roughly 600–700 MW of electricity at three different sites, and the GE-Hitachi (GEH)-designed SMR plants delivering roughly 300 MW of electricity at two different sites:

- Case 1 evaluated a NuScale SMR at the Idaho National Laboratory as a potential UAMPS project. This case provides the estimate of a first-of-a-kind (FOAK) SMR.
- Cases 2 and 3 evaluated a NuScale SMR and a GEH BWRX-300 at the Energy Northwest (ENW) site in eastern Washington State. The site had been evaluated previously for a light water reactor (LWR) nuclear power plant construction. Cost reductions associated with leveraging existing infrastructure and documentation on the site, the benefits of building the plant in proximity to an operating boiling water reactor (BWR) plant (Columbia Generating Station operated by ENW), and the benefits of constructing a plant in an area that already has a skilled nuclear energy workforce were assessed. The two LCOEs are not comparable because the approach to estimating them is different. NuScale's costs are based on designs, while GEH is designing to a cost target.
- Cases 4 and 5 analyzed placing an SMR at a strategically important site in Washington State—the Centralia site where the last remaining coal plants in the state are located and will be closed by 2025.

[1] Gen I refers to the prototype and power reactors that launched civil nuclear power. All commercial Gen I plants in the U.S. have been permanently shut down. Gen II refers to power reactors designed in the 1960s/1970s. All commercial reactors currently operating in the U.S. are Gen II plants. Gen III refers to advanced Gen II type reactors, none of which have been built in the U.S. Gen III+ refers to Gen III type reactors that have evolutionary designs offering improved economics and expanded use of passive safety features. Two Gen III+ plants are currently under construction in the U.S. Gen IV refers to advanced reactor concepts that are a significant departure from LWR technology. No Gen IV plants have been built in the U.S.

With the loss of the coal plants, a source of dispatchable power will be lost. Two alternatives were evaluated. One evaluated replacing the coal plants with SMRs. A second option evaluated adding an SMR at the site but not at the current location of the facility. A brownfield site where coal had been previously mined was chosen and one NuScale SMR or two GEH BWRX-300s were evaluated.

1.2 Clean Energy Transformation Act

Washington State's CETA may provide opportunities for *flexible nuclear* power.[1] The law calls for carbon neutrality by 2030 and carbon-free power by 2045 in the state's electricity sector. The law applies to both investor-owned utilities and consumer-owned electricity—all electricity will be coming from non-emitting resources by 2045. The law calls for the elimination of coal by 2025 and imposes potential penalties for electricity generation for all carbon-emitting resources starting in 2030 (WA 2019). The movement to non-dispatchable variable resource generation will require flexible non-carbon-emitting resources to meet ramping and frequency regulation requirements. SMRs are a probable resource for meeting the required flexibility, as are renewable methane (made with green hydrogen and carbon dioxide [CO_2]), renewable natural gas from decomposition of organic matter, and natural gas combined-cycle (NGCC) generators with carbon capture and sequestration (CCS) (Roberts 2019).

Beginning in 2022, utilities must develop plans that lead to carbon neutrality by 2030 and carbon-free generation by 2045. Utilities must pursue conservation measures first to meet load and then renewable resources and non-emitting resources for 100 percent of load. Between 2030 and 2040, utilities can satisfy up to 20 percent of their retail sales using alternative compliance options. Starting in 2030, compliance with the law can be achieved by providing a compliance payment, using unbundled Renewable Energy Credits (RECs), investing in energy transformation projects, and/or using energy recovery facilities to generate electricity.

Compliance payments are based on \$150/MWh for coal generation, \$84/MWh for natural gas generation, and \$60/MWh for NGCC generators (WA 2019). These payments are consistent with a \$150/T CO_2 tax. Unbundled RECs could provide the lowest cost of the approaches because they have been as low as \$0.35/REC for 1 MWh of renewable generated electricity (EPA ca 2018). As recently as 2019, the price of a REC was below \$1. Thus, a very inexpensive choice may be used by most Washington State utilities to meet their requirements. As of 2018, only 17.5 percent of electricity generated was from natural gas or coal (see **Table 1.1**) (WADOC 2019). The latest utility-by-utility information indicates that three investor-owned utilities and two Public Utility Districts (PUDs) accounted for 77 percent of the carbon-emitting resources in 2016. Thus 62 of 67 utilities may be able to purchase RECs to meet their obligations before 2045 while the remaining 5 utilities may purchase RECs for a portion but will be required to make the compliance payment on the remaining emitting resources (WADOC 2017) if they do not obtain non-emitting generation resources. The remaining amount that needs to be filled by non-emitting resources or pay the penalty is about 13 TWh currently or 1.5 to 2.0 GW.

[1] *Flexible nuclear power* moves beyond inflexible baseload electric generation and delivers carbon-free electricity, and other useable commodities such as process heat, to complement intermittent and variable generation sources.

Table 1.1. 2018 fuel mix for power generation in Washington State.

Fuel Type	Total Electric Power (MWh)	Share of Total (%)
Hydro	55,340,207	59.16
Unspecified	12,095,395	12.93
Coal	9,556,048	10.22
Natural Gas	6,861,147	7.33
Nuclear	4,441,378	4.75
Wind	4,288,021	4.58
Biomass	417,963	0.45
Solar	263,695	0.28
Biogas	184,859	0.20
Other Biogenic	42,931	0.05
Waste	35,627	0.04
Petroleum	15,854	0.02
Geothermal	3,540	0.00
Total	**93,546,665**	**100.00**

The law also constrains retail price increases to 2 percent per year (WA 2019), which may push energy conservation and RECs as low-cost options for achieving compliance. Utilities can also meet the 20 percent compliance requirement by building carbon-reducing infrastructure such as electric car charging stations, or weatherization, or investing in renewable natural gas facilities. An open question is whether there will be enough unbundled RECs or enough viable energy conservation projects to meet the 20 percent requirement, which could lead to a higher amount of capacity being required.

New hydroelectric generation is restricted in the Act so that new hydro generation will probably not be allowed as a new non-emitting generation source. All existing hydroelectric generation is allowed, but no impoundment of streams and rivers, expansion of reservoirs, bypass reaches can be used for new generation. Hydroelectric energy can be developed for pumped storage as long as it does not conflict with fish recovery plans and complies with all laws. The law does allow hydroelectric generation on canals, in irrigation pipes, or other manmade waterways (WA 2019). Thus, some new NGCC with CCS, small hydroelectric, land fill gas, and biomass plants may compete with SMRs in meeting flexible generation requirements.

The Northwest Power Pool is considerably more dependent on coal and natural gas than the state of Washington. Coal and natural gas provide more than 38 percent of the mix. The Northwest Power Pool represents more of the fuel mix for the Energy Imbalance Market (EIM) than the current supply balance with bilateral contracts for Washington utilities. With the entry of most of the Pacific Northwest into the EIM, a question for rulemaking will be how Washington State handles the EIM mix of emitting and non-emitting resources.

Rulemaking is managed by the Washington State Department of Commerce. The process will make some provisions and implementation of the law clearer. Washington electricity carbon emissions contain 95 g/kWh, while the U.S. averages 450 g/kWh, primarily because the Washington electric grid relies primarily on hydro and nuclear energy (EIA 2019c).

1.3 Commercial Nuclear Energy in the Pacific Northwest

ENW, formerly the Washington Public Power Supply System, was established in 1957. The current nuclear power plant, Columbia Generating Station (CGS), is located 8 miles north of Richland, Washington, at the site of nuclear power plant 2 (WPN-2) at Hanford. The plant cost $7.63 billion (2018$) to construct and has a net capacity of 1,174 MWe. In fiscal year (FY) 2018, CGS generated 9,722 GWh at a cost of $35.6/MWh and in FY 2019, it generated 8,873 GWh at a cost of $47.6/MWh. The fluctuation depends on the timing of the refueling outage and other activities (ENW 2019). The projected levelized cost of electricity (2014–2043) is between $47/MWh and $52/MWh (ENW 2020). They are selling power at cost to the Bonneville Power Administration (BPA).

Initially, ENW attempted to build five nuclear generating facilities. The projects' cost estimate reached almost $24 billion in 1981. WNP-4, at Hanford, and WNP-5, at Satsop, Washington, neither project supported by BPA, were discontinued in 1982. ENW completed WNP-2, at Hanford, and has two partially completed plants—WNP-1 and WNP-4 at Hanford. Significant effort was put into determining whether the two plants should be completed. WNP-4 has been put through a restoration process involving the removal of equipment and materials and 28 of the 30 prefabricated buildings. Two other plants, WNP-3 and WNP-5, at Satsop, Washington, were turned over to the Satsop Redevelopment Project. Currently, BPA is paying for the upkeep of the two plants and is responsible for the restoration costs if alternative uses cannot be found. If the sites are returned to brownfield status, the costs for the two sites could be as high as $100 million. The WNP-1 site was 70 percent complete when construction was stopped on the traditional large Gen II nuclear plant. WNP-1, referred to as Site 1 in this study (Case Study 2 and Case Study 3), is now a potential site for SMRs because a significant amount of the construction and infrastructure has already been completed (Miller 2013).

1.4 Report Contents and Organization

The ensuing sections of this report review the characteristics of nuclear power plants (Section 2.0), and present information about and approaches to estimating LCOEs derived from reviewing related literature (Section 3.0). The current energy market and projected electricity demand are discussed in Section 4.0. The case studies analyzed to determine the feasibility of introducing SMRs to meet the goals of zero carbon emissions are presented in Section 5.0, followed by discussion in Section 6.0 of firm and near-firm renewable energy grid generation resources that may provide competition to SMR generation. Finally, the results derived from the case studies that evaluated the NuScale SMR and GEH's BWRX-300 are analyzed in Section 7.0, and study conclusions are presented in Section 8.0. Appendix A contains related questionnaires developed to estimate the LCOE for the SMRs.

2.0 Review of Nuclear Power Plant Characteristics

Flexible nuclear power technologies that have evolved in the past decade can provide significant benefits—including characteristics that assist the electric grid in operating reliably and flexibly when siting the technologies—when transitioning to the emerging clean energy market of tomorrow. Nuclear power technology is one of the few carbon-free sources that can provide flexibility in deployment in terms of total electrical output (from 1 MW to more than 1,000 MW depending on the design), and newer technologies are free from many siting constraints associated with wind, solar, geothermal, and hydro installations. Indeed, modern nuclear installations may not require emergency evacuation zones and some technologies will discharge excess thermal energy to the air instead relying on water from a river or another source.

This section summarizes SMR characteristics that are important for assuring smooth operation of the electric grid.

2.1 Electrical Generating Characteristics Relevant to the Emerging Clean Energy Market

The characteristics of flexible nuclear power summarized in this section support a range of electrical distribution networks in assuring optimal, reliable, and efficient operation of the electrical grid. While discussion here is relevant to electric grids of today, the emerging clean energy market of tomorrow will drive innovation in the infrastructure toward new kinds of capable, flexible, and affordable *generating assets*.[1] From highly integrated and robust multi-gigawatt–scale electric distribution networks (such as that operated by BPA) to isolated networks of the megawatt scale, integration of large amounts of variable or intermittent generating sources in the electric distribution and consumption network requires adaptable, flexible, and dispatchable generating (and energy storage) assets to make sure reliable on-demand delivery of electricity is available to augment variable and intermittent sources.

Electric generating assets of the emerging market may require adaptability to local natural resources. For example, the geographic location of a localized megawatt-scale electric network may not provide adequate cooling water sources for operation of a traditional steam turbine/generator system to reject excess heat through the steam cooling towers used by plants such as CGS. Or, environmental permits may not be readily secured for a project. Or, there may be a large commercial facility, such as a paper mill, that can use the residual thermal energy left over from electric generation.

Even when supporting today’s large BPA electric distribution network, the mixing and matching of generating characteristics is necessary to make sure an electric grid functions on the hottest days and coldest nights. This requires a mix of reliable and affordable baseload generation and dispatchable generation that covers the daily and seasonal variations in electric consumption.

The challenges faced in operating the BPA electric distribution network are illustrated in **Figure 2.1**. The figure illustrates the *average* monthly net load[2] for 2019 and the average daily load in February 2019

[1] A *generating* asset in this section refers to any system that can deliver net-positive usable electricity to the electric grid at 60 Hz. Novel technologies may incorporate generation and storage capabilities for instance, but unlike an electric (battery), pumped storage, or thermal energy *storage* asset, the generating asset is capable of net positive contributions of power.

[2] Net load represents loads within BPA's Balancing Authority and does not include loads transferred out of the region or scheduled for use by customers with their own Balancing Authorities, such as Seattle and Tacoma.

using data obtained from BPA.[1] As illustrated here, the average monthly load varied by over 2,100 MW between February and September that year. And *within* the month of February, the average daily load varied (coincidentally) by more than 2,100 MW. This variation in load is nearly equivalent to twice the output of CGS. The challenge is further illustrated in **Figure 2.2** which displays the BPA net load based on 5-minute interpolated data for February 2 through 5 of 2019.[2] Over this period of time, the change in net load was 4,400 MW—which is four times the total output of CGS. Also shown in the figure is the total wind generation for the days for which BPA is responsible for accounting. Note that **Figure 4.3** (in Section 4.2) shows the variation of electricity costs for the year—and an especially strong change in costs during this time period.

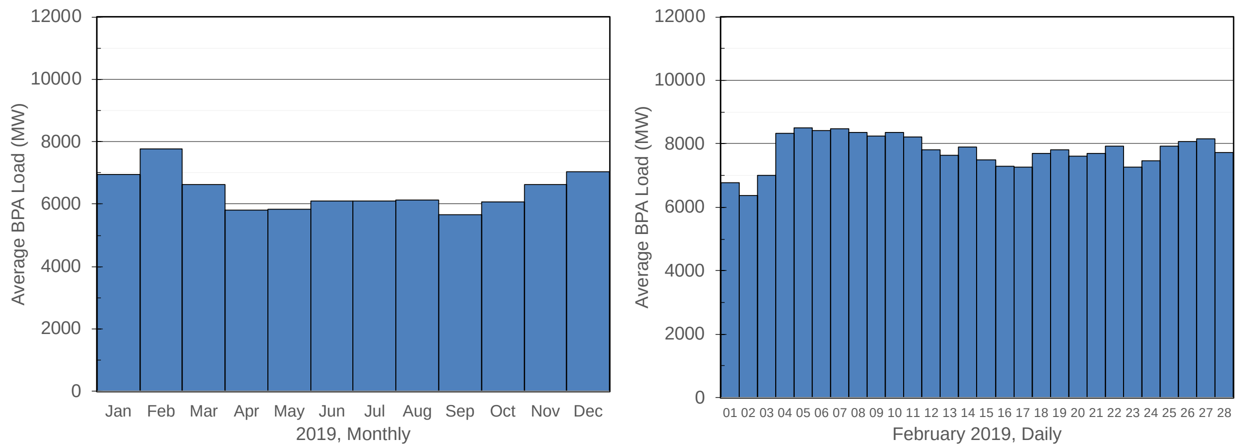


Figure 2.1. 2019 monthly and February 2019 daily average load on the BPA network.

During the timeframe depicted in **Figure 2.2**, wind only provided significant generation on February 3 when it generated the equivalent of 22,000 MWh of energy—which if stored and returned to the grid in the future with 100 percent efficiency over a 24-hour period would represent 917 MW of continuously delivered electricity throughout the future day.

[1] See https://transmission.bpa.gov/business/operations/wind/ item "Data for BPA Balancing Authority Total Load, Wind Gen, Wind Forecast, Hydro, Thermal, and Net Interchange."
[2] The dates represent the lead up to, and initial phase of, a significant winter storm in the Pacific Northwest.

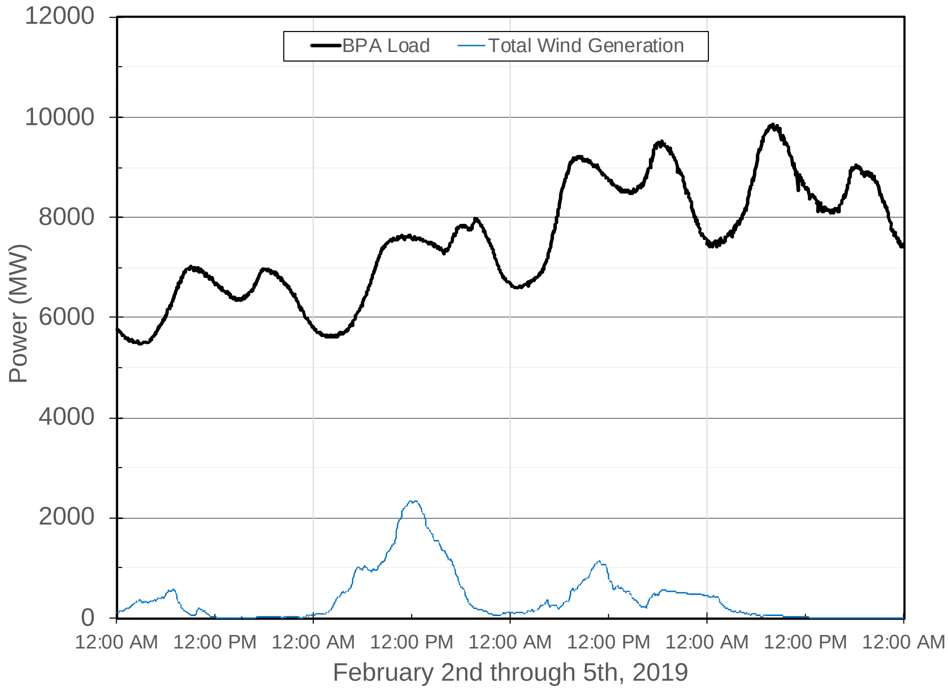


Figure 2.2. Net load and total wind generation on select days.

The fundamental challenge to a modern electric grid is that electricity is ephemeral—there is currently no affordable and large-scale capability to store 1,000s of megawatt-hour equivalents of energy generated in one moment for future use. And this is the driver for innovation in flexible nuclear power technologies—to deliver carbon-free infrastructure to deliver the capable, flexible, and affordable generating assets needed for the emerging clean energy market of tomorrow.

Several generating characteristics summarized in the following sections are anticipated to be important to the emerging electric generation network. The inherent value of a project is increased for a flexible nuclear power generating asset if it incorporates any of these characteristics. However, "pricing-in" this inherent value into a pure economic analysis is challenging (some examples are addressed later in this document), especially for the innovations that will drive the emerging clean energy market of tomorrow that has not yet arrived. See *IAEA Nuclear Energy Series No. NP-T-3.23* for additional information in a broader worldwide context (IAEA 2018).

2.1.1 Beyond Baseload

Baseload electric supply involves delivery of ultra-cheap electricity with uninterrupted performance over a period of weeks and months. Generating assets delivering baseload electricity, such as the current fleet of nuclear power plants and modern NGCC plants, are highly optimized with complex arrangements of systems that maximize *thermal efficiency*[1] for the cheapest attainable electric cost. And baseload units may not function as efficiently at reduced power levels. Overall, the performance of these assets is measured by the *capacity factor*, the percentage of time during the year that an asset generates power at its rated power level. Increased costs associated with the complexity of baseload generating assets are recovered by maximizing the capacity factor, and hence revenue through the near-continuous generation of electricity.

[1] Thermal efficiency is the efficiency of converting chemical or nuclear heat released from fuel into electricity. A high efficiency means less fuel is consumed per unit of generated electricity.

Electric consumption varies widely throughout the day and the season based on consumer demand, commercial activity, and environmental conditions, as illustrated earlier in **Figure 2.1** and **Figure 2.2**. And, any electric grid that has significant penetration of non-dispatchable intermittent electric generating assets requires dispatchable assets that have the flexibility to adapt to the generation swings, sometimes called peaker units, as the wind dies down, or clouds develop, or as river flows decrease later in the summer months and fall. A large portion of this variation and intermittency can be forecast by electric grid operators a day or a week ahead based on current conditions and a dispatch notice sent to a generator to cover the needs. Mitigating these *forecastable* swings in electric supply using assets designed for large capacity factors, such as current nuclear or combined-cycle natural gas units, is technically challenging and other assets are preferred. A *simple-cycle* natural gas plant that is relatively cheap to build and can power up/down rapidly, but much less thermally efficient than a NGCC plant, may be an affordable option to cover daily demand swings, for example. The electric supply market pays a premium for assets that can respond to daily and/or seasonal swings in electric energy consumption.

Historically, generating assets that have relatively low construction costs (up-front investments) that may have a larger fuel cost have played an important role in fulfilling dispatchable beyond-baseload generation needs in many electricity networks—especially simple-cycle natural gas plants. And in the Pacific Northwest, this service is in part fulfilled by hydroelectric generation. However, with decarbonization goals and with increased consideration of hydroelectric generation impacts on river ecosystems, the emerging clean energy market will expand beyond simple-cycle natural gas and hydropower for carbon-free beyond-baseload generating capacity to fulfill forecastable electric power generation demand.

Several characteristics listed below are incorporated into flexible nuclear power plants to increase their inherent value in delivering dispatchable electric generation and for transcending the traditional baseload generation role of the current nuclear power plant fleet. These characteristics are incorporated through purposeful decisions during the design process and may involve compromises in terms of the thermal efficiency, fuel costs, and construction costs of a plant. All flexible nuclear power plants that are currently being designed can be tailored, to varying degrees, to specific situations for providing electric power generation to account for forecasted demand and generation changes.

- Seasonal load swings – as illustrated in **Figure 2.1** on a monthly basis, the Pacific Northwest is unique in the U.S. in that the regional authorities may order large non-hydro baseload plants to curtail generation during the spring runoff season when electric demand is low and hydro generation is maximized.
- Variable daily load swings – as illustrated in **Figure 2.2**, every electric grid experiences daily variation in electric energy consumption. This occurs for many reasons throughout the day, including industrial demand, heating/cooling loads, and other causes—and unique *shapes* occur in the daily demand curve depending on summer (cooling) and winter (heating) conditions.
- Intermittent *forecasted* generation changes – windy seasons, prolonged weather inversions, and forecasted droughts that dampen river flows that result in forecasted decreases in renewable generation assets are examples of knowable generation changes that must be accounted for.

Note that some current nuclear power plants located outside the U.S. already have the capacity to ramp electrical generation up/down by 20 percent per hour and follow the variable daily and intermittent forecasted load swings. An analysis by Buongiorno et al. (2020) indicates such a plant could meet 92–98 percent of all variable generation under the conditions of the study.

The means by which several nuclear plants achieve these characteristics are discussed later.

2.1.2 Response to Rapid Changes in Generation or Demand

The electric grid undergoes minute-by-minute changes in supply and demand for electric power. This is only slightly noticeable in **Figure 2.2** as minor fluctuations in the 5-minute interval data (see for example the period around noon on February 5). Whether a generator goes offline unexpectedly, or demand suddenly increases, the grid operators must have resources to call upon to rapidly fulfill these un-forecasted changes in electric generation. For example, challenges in February 2009 saw more than 700 MW of wind generation that was being delivered to the BPA grid be curtailed in a period of 5 minutes.[1] This particular instance was preceded by a rapid increase in more than 700 MW of wind generation just a few hours before. Such dramatic systematic changes in generation are well documented for grids that have large renewables penetration.

2.1.3 Island Mode

Electrical generation in the U.S. requires that generators deliver electricity with a 60 Hz frequency within a very tight tolerance. For most generating assets that use a traditional rotating generator and are connected to a large *and functional* grid, the rotating generator operates synchronously to the grid and cannot control its own rotating speed. The ability to regulate the frequency of *supplied* electricity is referred to as island mode. This mode is critical for operation of isolated grids (such as a small community or island) to assure proper function of the grid. The ability to operate in island mode is primarily a feature of the electric generator and associated equipment. However, considerations are necessary for the electrical components, pumps, fans, etc. that are used in the power plant to assure proper functioning. This ability is also tied to the black start capability described below.

2.1.4 Black Start Capabilities

With some exceptions, independent regions of the modern electric generation and distribution network in the U.S. have worked almost continuously for more than 100 years. However, one notable event was the Northeast Blackout of August 14, 2003, during which large parts of the electric grid New York, New Jersey, Pennsylvania, Ohio, and Canada stopped operation for several days.

The challenge of (re)starting an electric grid of any scale is that it generally takes electricity to make electricity. Whether to run pumps to inject fuel, operate coal elevators, or to operate pumps to circulate cooling water around a plant, nearly every kind of power plant needs power to operate its systems. Then, once electric generation starts the plant must be able to regulate the output electric frequency so that other power plants can draw on this source of energy to start their systems.

The current fleet of nuclear power plants requires significant energy to operate pumps to circulate coolant through the reactor core under normal operating conditions. For the largest plants, the needed electricity can exceed 20–40 MW to operate essential house electric loads. However, several flexible nuclear power plants currently being designed do not use such coolant pumps. And with other careful considerations, nuclear power plants may be capable of starting up by using locally available electric supplies such as diesel generators and providing a black start capability for other generators on the grid.

[1] See BPA. 2009. "How BPA supports wind power in the Pacific Northwest." https://www.bpa.gov/news/pubs/FactSheets/fs200903-How%20BPA%20supports%20wind%20power%20in%20the%20Pacific%20Northwest.pdf.

2.1.5 Additional Services

Additional services, some of which are called *ancillary services*, incorporate a broad set of beyond-baseload capabilities that can be sold to electric grid operators by providers in deregulated or capacity markets. Examples are provided below and can be tracked back to the discussions earlier in this section—they are related to the operation of the grid, swings in demand, and the need to balance grid operations.

1. Arbitrage – Trading in the wholesale energy markets by buying energy during off-peak, low-price periods and selling it during peak, high-price periods.
2. Capacity or Resource Adequacy – A provider is dispatched during peak demand events to supply energy or to reduce consumption (generating electric and *not* consuming it are equivalent in this case). The service reduces the need for new peaking power plants and other peaking resources.
3. Regulation Up and Down Services – A provider responds to a strong imbalance in supply and demand in order to provide a corrective response to all or a segment of an area. This ensures near instantaneous and continuous balance of generation and load.
4. Frequency Response – The provider delivers energy in order to maintain frequency stability when it deviates outside the set limit, thereby keeping generation and load balanced within the system. This is achieved by dispatching energy whenever deviations beyond set limits occur, thereby keeping load and generation within the system balanced.
5. Spinning/Non-spinning Reserve – Spinning reserve represents capacity that is online and capable of synchronizing to the grid within 10 minutes. Non-spinning reserve is offline generation capable of being brought onto the grid and synchronized to it within 30 minutes.

2.2 Overview of Generation III+ Small Modular Reactor Concepts

A wide range of flexible nuclear power technologies are currently under active development. A large number of the designs are considerably smaller than the electrical output of CGS on an individual unit or module basis, but some of them are designed to be built in groups or clusters of modules that can reach an output similar to that of CGS based on the electrical supply needs of the region. The Advanced Reactor Information System (ARIS, https://aris.iaea.org/) is an online database maintained by the International Atomic Energy Agency that is designed to easily obtain up-to-date overview information about reactor technologies being developed and deployed around the world. From the database, interested readers can obtain design-specific information, such as electrical output, provided by the developers for these concepts. Given the easy access to information, a broad survey of flexible nuclear power technologies is not provided here. The NuScale SMR and GEH BWRX-300 designs are of particular interest in this report and are discussed in a little more detail later in this section.

Approval of a commercial nuclear power reactor in the U.S. requires licensing by the U.S. Nuclear Regulatory Commission (NRC). There are multiple pathways for licensing of a new plant. One pathway is by submission of a *Design Certification Application* (DCA) by a nuclear technology developer to the NRC. This DCA submission is a very significant milestone that involves disclosure of a large collection of reports and documents about the proposed technology. Approval of this application takes several years of technical review by the NRC and a formal rulemaking process. A completed rulemaking certifies a nuclear power plant design, independent of an application to construct or operate the plant. A list of all certified and in-process applications can be found on the NRC website at https://www.nrc.gov/reactors/new-reactors/design-cert.html. Links on the page to each design provide access to the large collection of reports and documents, as well as information and communications exchanged between the NRC and the applicant. Considering the depth and detail that must be submitted for scrutiny and the extensive cost of the review, a DCA submitted by a nuclear technology developer demonstrates significant maturity in the design and strong financial commitment to the endeavor by the developer.

2.2.1 NuScale SMR

A single NuScale SMR module is a compact design in which key components are contained within the reactor vessel. The design is novel because it uses *single-phase* natural circulation processes to circulate cooling water through the fuel contained in the nuclear core—no pumps are necessary to circulate cooling water in the primary circuit. Integration of the key components inside the reactor vessel and no reliance on recirculation pumps contribute to a significant increase in safety margins for this design over previous generations of nuclear power plants. An illustration of a single module is shown in **Figure 2.3**. While there is flexibility to use other numbers of modules, a NuScale plant in this study includes 12 modules. Key design data are listed in **Table 2.1** for the NuScale SMR plant (all data in the table are from documents submitted to the NRC).

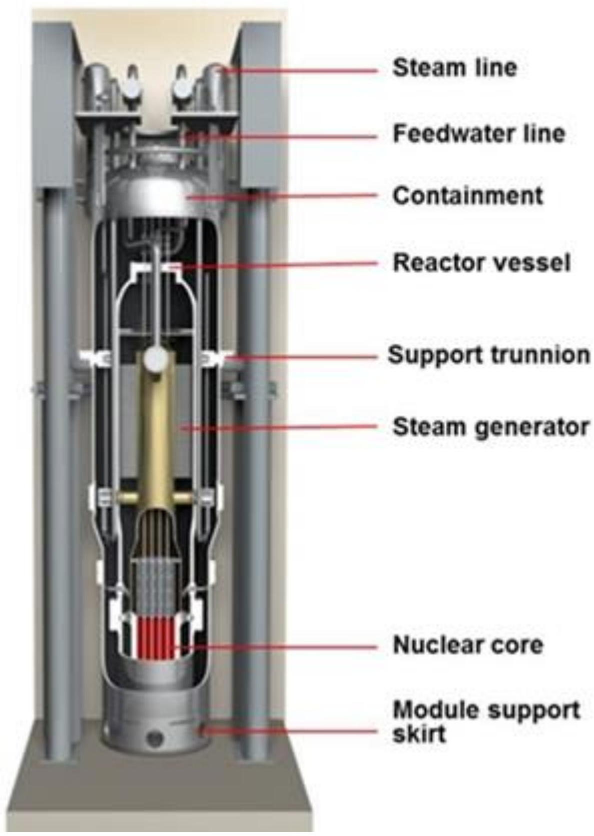


Figure 2.3. Schematic of one NuScale SMR module.[1]

[1] NRC. "Design Certification Application – NuScale." Accessed August 3, 2020 at https://www.nrc.gov/reactors/new-reactors/smr/nuscale.html

Table 2.1. NuScale SMR design data (12-module plant).

Attribute	Value
Thermal capacity	1,920-2,400 MWt*
Electrical capacity	600–720 MWe (gross output)[a]
Capacity factor	>95%
Fuel design	Standard design consistent with existing pressurized water reactors, but shorter; 37 assemblies per module.
Fuel form	Pelletized uranium dioxide form with <5% enrichment
Refueling interval	24-month
Operating lifetime	40 years – initial NRC license duration 80 years – with life extension

(a) Thermal and electrical capacity indicate two values. The first value is consistent with regulatory submittals in 2017. The latter value reflects a planned uprate addressed in the forthcoming “NuScale720” Standard Plant submittal.

Considering the electrical generating characteristics in Section 2.1, a number of publications describe the flexibility and capabilities of the NuScale SMR to deliver these characteristics. See, for example, the paper by Ingersoll et al. (2015) that addresses integration with wind-generating sources. A number of these capabilities were incorporated into the design that is undergoing NRC review. For example, the indicated reference describes three ways to deliver longer-term to short-term load-following capability and ability to rapidly respond to electrical demand signals by

- taking one or more modules offline for extended periods of low grid demand or sustained wind output,
- maneuvering reactor power for one or more modules during intermediate periods to compensate for hourly changes in demand or wind generation, or
- bypassing the module’s steam turbine directly to the condenser for rapid responses to load or wind generation variations.

The reference goes on to describe realistic scenarios on the BPA electric grid and provide a technical discussion of how individual modules, and the plant as a whole, may respond. And, without pumps to circulate cooling water in the primary circuit that would require electric to operate them, and with careful design considerations for other systems, the NuScale plant is expected to be able to operate in island mode and provide black start capabilities. Pending in-field demonstrations, these features of the design appear to enable the NuScale SMR to provide reliable on-demand delivery of electricity to augment the variable and intermittent sources.

2.2.2 GEH BWRX-300

The GEH BWRX-300 plant is an evolution of the NRC-approved ESBWR (Economic Simplified Boiling Water Reactor) design, which itself draws many elements from earlier designs, including CGS. The plant is a compact design in which key components are contained within the reactor vessel. The design draws upon the ESBWR in using *two-phase* natural circulation processes to circulate cooling water through the fuel contained in the nuclear core—no pumps are necessary to circulate cooling water in the primary circuit. Integration of the key components inside the reactor vessel and no reliance on recirculation pumps contribute to a significant increase in safety margins for this design over previous generations of nuclear plants. An illustration of a single plant is shown in **Figure 2.4**. A single site can contain a single plant or multiple plants. Key design data (provided by the designer) are listed in **Table 2.2** for the BWRX-300 plant.

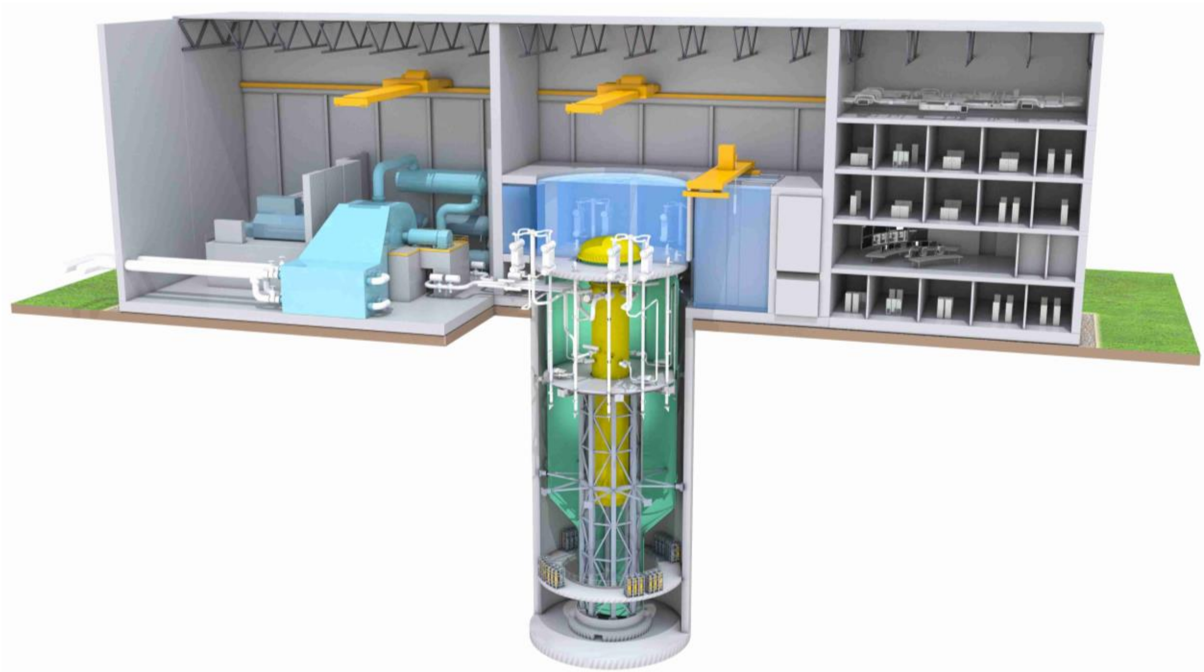


Figure 2.4. Schematic of the GEH BWRX-300 plant layout.[1]

Table 2.2. GEH BWRX-300 design data.

Attribute	Value
Thermal capacity	870 MWt
Electrical capacity	300 MWe (gross output)
Capacity factor	>95%
Fuel design	Standard design consistent with existing boiling water reactors, but shorter.
Fuel form	Pelletized uranium dioxide form with <5% enrichment
Refueling interval	Up to 24-month interval
Operating lifetime	60 years – proposed NRC initial license duration

GEH has not yet submitted a DCA to the NRC for review so detailed design data are not publicly available. However, technical review of the design shows it can achieve many of the electrical generating characteristics described in Section 2.1. However, the rates at which the plant can respond to electrical load changes cannot be determined without detailed data. The plant operates without pumps to circulate cooling water in the primary circuit that would require electricity to operate them, so it is expected the design can operate in island mode and provide black start capabilities if certain decisions are made during the design process.

Pending more detailed design data and in-field demonstrations, the design of the BWRX-300 plant is expected to provide reliable on-demand delivery of electricity to augment the variable and intermittent sources.

[1] GE-Hitachi. "BWRX-300." Accessed August 3, 2020 at https://nuclear.gepower.com/build-a-plant/products/nuclear-power-plants-overview/bwrx-300

3.0 Significant Relevant LCOE Studies and the Approach to Estimating LCOEs

Relevant LCOEs for SMRs and large nuclear power plants are reviewed in this section.

3.1 LCOE Literature

Recent studies of the LCOE for SMRs show nth-of-a-kind (NOAK) reactors with costs from $65 to $100/MWh. Conventional nuclear power takes advantage of economies of scale, while small nuclear reactors try to offset that advantage with the ability to manufacture modular components in a factory setting. The factory setting takes advantage of a trained workforce within a specified quality assurance setting to avoid the construction delays associated with the increased cost of capital. The big question for modularization is whether it can reduce the capital cost because that is where the largest improvement in cost can occur. The combination of fuel costs and operations and maintenance (O&M) costs is estimated in the $29/MWh to $42/MWh range and these costs are much better understood than engineering designs, costs to construct, and the time cost of money associated with construction.

New construction of conventional nuclear power indicates the capital costs are a significant deterrent to competitive electricity generation. Lazard's paper (2019) noted that the cost of capital provides a significant difference in the LCOE of new nuclear power. It noted that for unsubsidized power, the LCOE ran between $118/MWh and $192/MWh for after-tax internal rates of return (IRRs) of 5.4 and 9.2 percent, respectively. See **Table 3.1** for comparison of conventional nuclear power's cost at the low end and high end from the Lazard (2019) study. These costs for new-build nuclear plants contrast with current operating nuclear reactor costs. A recent study by the Nuclear Energy Institute (NEI 2018) indicated costs of $29/MWh and $42/MWh with an average of $32/MWh. According to NEI, fuel costs do not significantly distinguish between the large nuclear reactors. NEI data indicate that fuel costs are about $6–$7/MWh rather than the $9/MWh indicated by Lazard.

Table 3.1. Comparison of conventional nuclear cost at the low and high end ($/MWh) from the Lazard (2019) study

Cost Type	Low End	High End
Capital Cost	91	162
Fixed O&M	15	17
Variable O&M	4	4
Fuel	9	9

MIT estimates that if modularization could reduce construction time and costs by 20 percent, the overnight costs of capital could decline by $1,000/kWe (Buongiorno 2018). Their forecasted reduction in overnight capital costs was based on the reductions in cost for modularization in the chemical plants, offshore oil and gas platforms, and liquified natural gas plants. The MIT report discusses modularization success in the nuclear industry and nuclear submarine builds. They estimate that the reduction in overnight capital costs would reduce the interest and ownership costs by one-third, providing an overall savings of $1,600/kWe in installed costs.

The MIT study provided capital estimates for advanced reactors (**Table 3.2**) and indicated the costs ran from $5.2 billion to $6.1 billion for reactors sized between 2,400 MWt to 3,400 MWt for conceptual and pre-conceptual design. Based on estimates in the study, the LCOEs are provided. The values shown in **Table 3.2** would have been in the $110/MWh to $115/MWh range if a common O&M cost had been used. The capacity factors were estimated uniformly across reactor types at 90 percent according to the study.

MIT also provided literature review estimates for the Advanced Passive 1000 (AP1000) reactor and the NuScale SMR. The AP1000 overnight costs rose dramatically from a certified public utility commission estimate of $4,500/kWe to $8,600/kWe. The cost estimate for NuScale increased from $1,200/kWe, a pre-conceptual cost estimate, to $5,078/kWe (2014$) ($5,800/kWe in 2019$ [escalated using the Handy-Whitman utility cost index as reported by the Pennsylvania Jersey Maryland Independent System Operator [PJM 2019]) as a Class 2 estimate. The costs were estimated by Fluor in 2014. The LCOEs were estimated to be from $102/MWh to $112/MWh (2016$) ($108/MWh to $120/MWh in 2019$) for a FOAK plant (Surina 2016). The values include ownership costs of $6/MWh. The range is based on investor-owned utility (IOU) financing of 55 percent debt at 5.5 percent and the remaining equity costs at 10 percent. Based on municipal financing, the costs decrease to $81/MWh. There is some confusion about whether this was really a Class 2 estimate given the time differential between 2014 and 2020. A year earlier, the LCOE was estimated to be 101/MWh for a FOAK and $90/MWh (2012$) for the NOAK. The FOAK and NOAK LCOEs in 2019 are approximately equal to the year-later presentation (Surina and McGough 2015). The increase in costs from conceptual to the current estimate indicates just how much cost estimates are likely to grow as the designs move closer to Class 1 estimates.[1]

A Hanford SMR (URS 2014a 2014b) study used industry-accepted costs of $2.5 billion for a 540 MWe multi-module SMR to undertake a study for TRIDEC, an economic development body located in Richland Washington. They estimated the LCOE to be in the $85/MWh range.

Table 3.2. Capital costs with interest for advanced reactors, according to an MIT 2018 report (Buongiorno et al. 2018).

	HTGR	SFR	Large FHR	FHR with NACC	MSR	ALWR	NuScale
Size	4 × 600	4 × 840	3,400	12 × 242	2,275		
Total Cost ($ mil.)	5,200	5,600	5,200	5,400	6,100		
Cost/MWh[(a)]	$118	$118	$116	$135	$120	$100	$96 - $106

(a) Costs are only valid at two significant digits, thus the differences are only included to show the relative difference. The NuScale estimate based on the Surina (2016) estimate NACC is the Nuclear Air-Brayton Combined Cycle.
ALWR = advanced light water reactor; FHR = fluoride-salt high-temperature reactor; HGTR = high-temperature gas reactor; MSR = molten salt reactor; NACC = Nuclear Air-Brayton Combined Cycle; SFR = sodium-cooled fast reactor.

A 2019 study (Energy Strategies) indicated the cost of NuScale's Idaho National Laboratory (INL) plant to be $65/MWh (2018$ or $66 in 2019$). The study evaluated the SMR LCOE at different levels noting that UAMPS and NuScale in a joint presentation estimated that the cost was between $45/MWh and 65/MWh. The study also noted that the PacifiCorp Integrated Resource Plan put the cost at $95/MWh.

Scully Capital and KutakRock (Kirschenberg et al. 2017) analyzed the premium the Tennessee Valley Authority would pay for using an SMR at the Clinch River site. Their base cost for the SMR was $80/MWh. After adjusting for the resilience benefits of black start ($8/MWh), resilience service fees

[1] According to NuScale, the actual estimates increased initially and are now decreasing. The NuScale scope of supply is Class 3 or better. The Engineer, Procurement, and Construction (EPC) scope of supply is Class 4 and has been decreasing. There are very good reasons for this based upon lessons learned from the AP1000 projects. As an example, the use of steel composite walls instead of traditional steel reinforced concrete can improve the schedule and reduce cost significantly. So far, Fluor has lowered the costs by $450 million through value engineering.

($6/MWh), and research and isotope fees ($2/MWh), a premium of $18/MWh remained above the cost of installing a NGCC facility estimated to have an LCOE of $54/MWh. No basis was provided for the SMR cost.

An Energy + Environmental Economics (E-3) study (Aas et al. 2020) used a portfolio approach to analyze the potential for an SMR to meet the requirements of providing power in the Western Electricity Coordinating Council (WECC) for ENW. That study used a NuScale capital cost of $4,900/kWe and in that report National Renewable Energy Laboratory (NREL) report estimated capital cost of $5,600/kWe. Both cost estimates for fixed O&M were $9.9/MW-yr.

The U.S. Energy Information Administration (EIA) indicates the average cost of advanced nuclear power is $6,317/kWe (2019$) for overnight cost. They also indicated there is an 8.7 percent added cost for building in the Pacific Northwest (EIA 2020a). They also calculated the LCOE for advanced nuclear power (2,256 MWe) to be $82/MWh, comprising capital at $56/MWh, fixed O&M at $16/MWh, variable O&M at $9/MWh, and transmission at $1/MWh. A production tax credit could reduce the LCOE by $7/MWh for entities that can monetize the tax credits. The production tax credit can be transferred by a capital injection into the project, but care must be taken to assure the availability of the tax credit. An advanced nuclear power reactor built in the Pacific Northwest would cost $90/MWh using the EIA regional cost tables. The EIA cost estimates do not include the cost of interest.

4.0 Current Energy Market and Projected Electricity Demand

The study documented here primarily depends on the Northwest Power and Planning Council's (NPCC's) Seventh Power Plan (NPCC 2019) for the forecast of power and bases Washington's market forecast on the NPCC plan. The forecast takes the most recent EIA data as the base for Washington State and lays the power plan on top of it. Because this study reaches beyond the scope of the power plan, potential changes in future demand were reviewed and evaluated. For example, the potential for electric vehicles to become a large portion of transportation by 2045 is examined. Note that this market evaluation was completed prior to the COVID-19 pandemic. The recovery from the pandemic in the U.S. and in the state of Washington could impact future projections.

4.1 Current Supply and Demand for Electricity

Washington State's 2018 electricity generating capacity is 30,983 MWe. **Figure 4.1** shows the capacity by major resource type. Approximately 5 GWe is natural gas and coal based. Hydroelectric generation accounts for about 69 percent of capacity. Nuclear and non-hydro renewables each provide another 4 and 11 percent, respectively. Approximately 15 percent of capacity is provided by fossil generation (EIA 2019a, 2019b). Coal generation, according to the Washington law, will be eliminated by 2025 or taxed at $150/MWh. All commercial coal generation in Washington State will be closed by 2025 (Varton 2018). The remaining 9 percent of installed capacity currently only operates 18–73 percent of the time, and the largest share operates at about 42 percent of capacity. Thus, natural gas can probably replace the loss of coal generation in the short term. In the longer term, the change in load will determine whether adequate generation capacity is available.

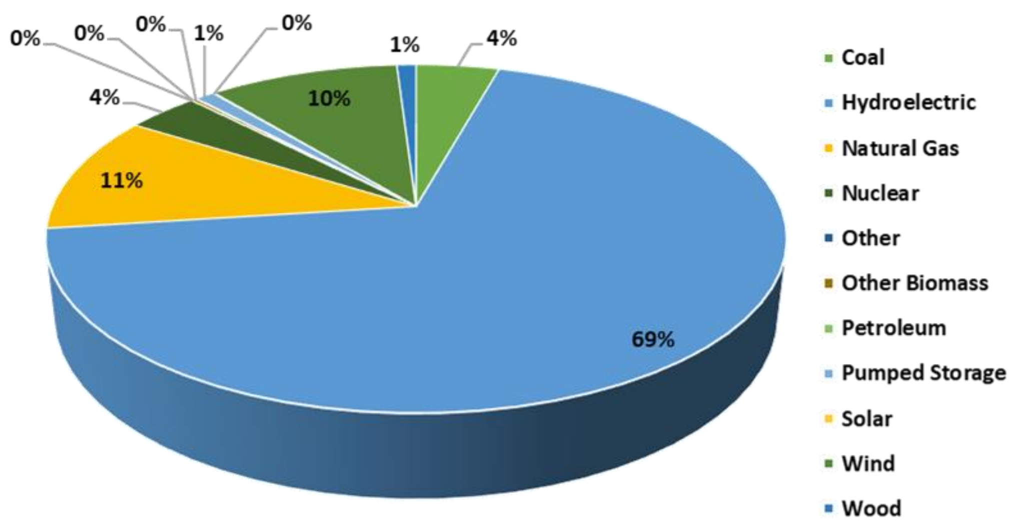


Figure 4.1. Washington State generation capacity by shares in 2018 (for a total generating capacity of 30,983 MWe).

4.2 Impact of BPA Entry into the Energy Imbalance Market

The BPA will likely enter the EIM in 2022[1] (BPA 2019a). A final decision will be made in fall 2021. This report assumes BPA will be in the EIM. With BPA's potential entry into the EIM, most of the Pacific Northwest will be covered, with exception of a small area in north-central Washington. Most of the load centers will be participants in the EIM. Certain parts of Washington are already a part of the EIM, including Seattle City Light, Puget Sound Energy and PacifiCorp West (Figure 4.2). Tacoma Power will join in 2022 as well. With BPA's entry most of the power in Washington will be delivered by transmission assets in the EIM. Currently, BPA owns 75 percent of the electric power transmission in the Pacific Northwest.

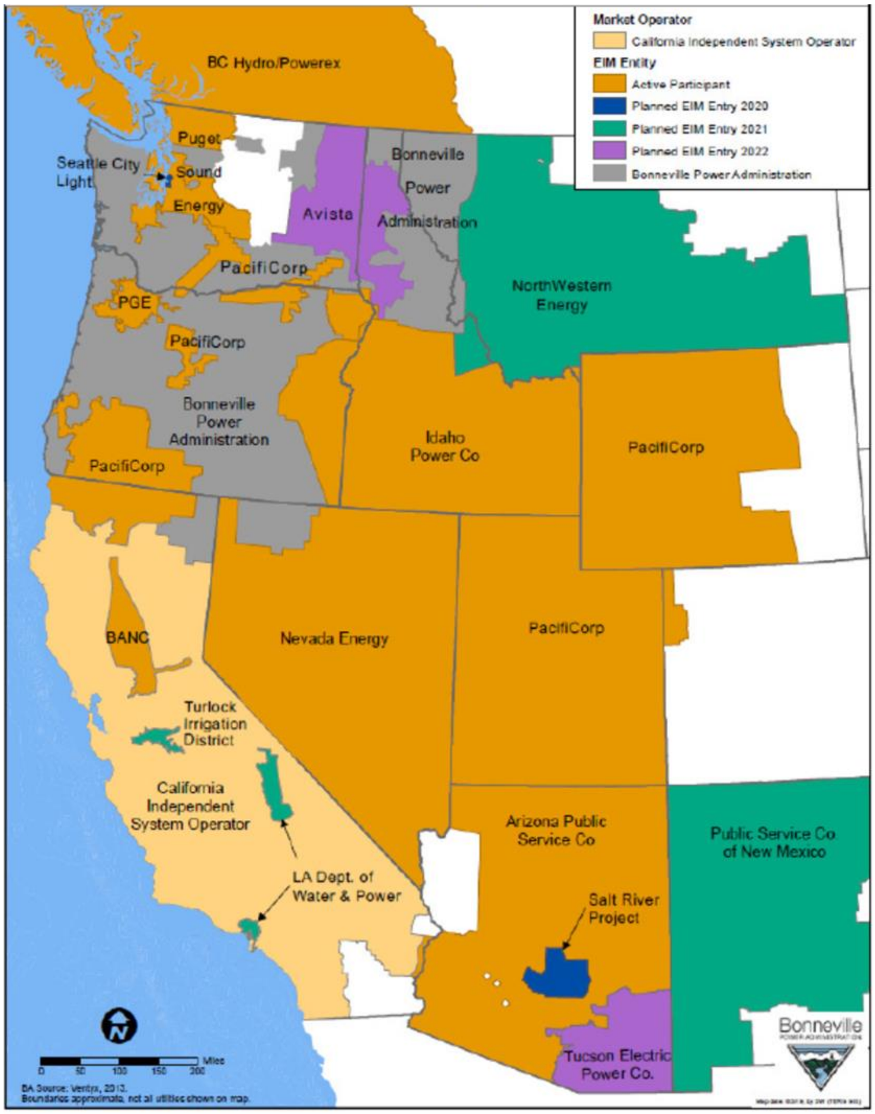


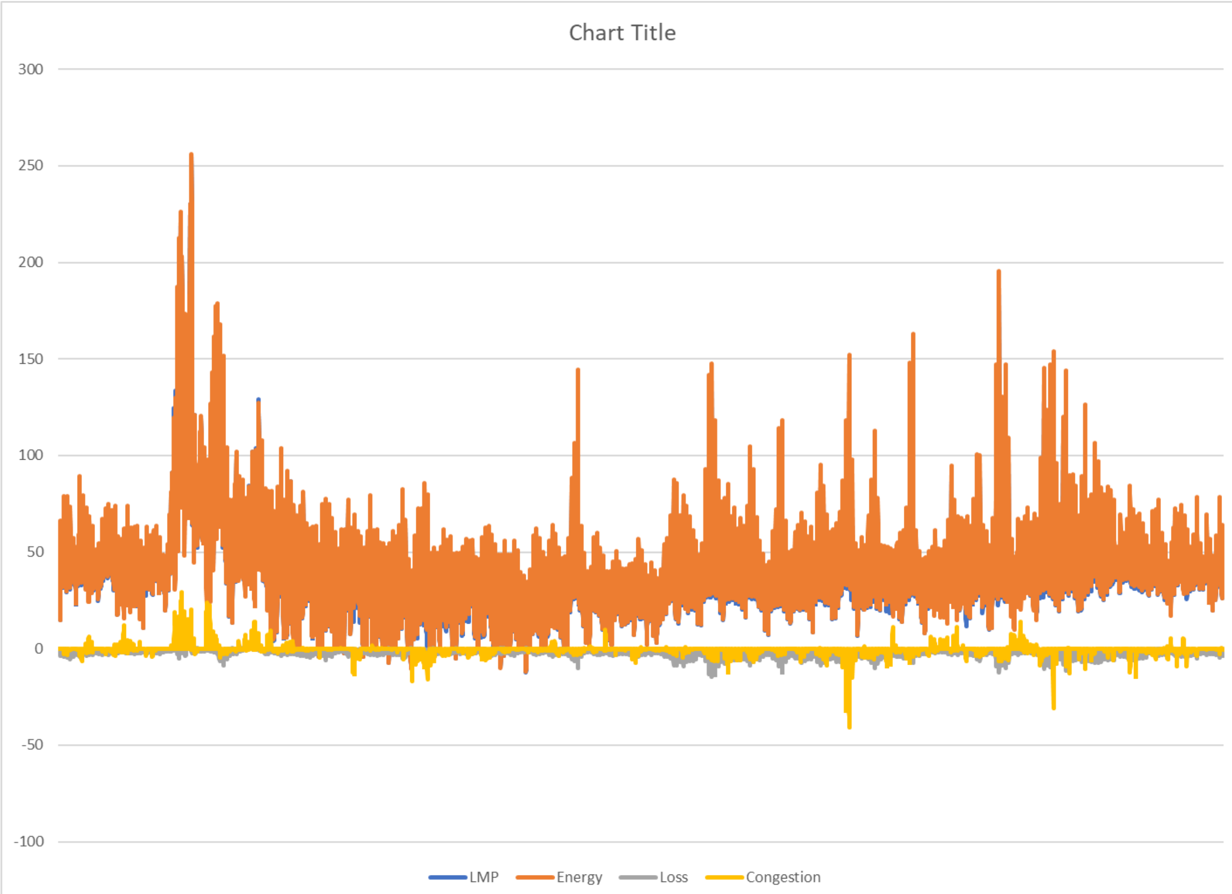
Figure 4.2. The Western Interconnect Balancing Authority Areas in the EIM in 2019.

[1] The energy imbalance market is the voluntary real-time market. The EIM allows cooperators to provide the lowest cost power to all the markets within its boundaries. The system gives each participant visibility into grid operations across all participating entities. The market allows the system to better integrate renewables in the system in real time.

BPA markets power from 31 hydroelectric projects with an installed capacity of 22 GW. In addition, BPA markets the power of other entities including ENW's CGS. BPA's energy mix is 97 percent carbon free (Florescu and Pead 2018). Few of the Federal Columbia River Power System dams are truly flexible given the constraints on the system and other purposes that the system must serve. The *Endangered Species Act*, navigation, flood control, irrigation, and recreation drive the amount of capacity available to meet generation and flexibility requirements. The overall capacity of the region's hydroelectric dams is 33 GW. The system can only generate 26 GW for 2 hours, 24 GW for 4 hours, and can only provide 19 GW for 10 hours. In addition, BPA's capacity includes ramping capacity of 1,000 MW per hour when ramping up but is very limited meeting down ramping capacity (Florescu and Pead 2018). In 2018, BPA only had 600–900 MW of firm transmission available to go to the EIM market (Florescu and Pead 2018). Providing flexibility is a primary reason to study the LCOEs of SMRs, because they may be able to provide the flexibility required to incorporate more variable resource renewables as indicated in a recent study by E-3 (Aas 2020).

Most of BPA's firm contracts will expire just before a potential SMR comes online in 2029/2030. Currently, BPA's firm rate is \$37.4/MWh. In addition, almost any plant in the Pacific Northwest may be able to participate in the EIM. Thus, wholesale market prices will be strongly influenced by the EIM average plus or minus transmission losses and congestion costs.

Because Washington State is a net exporter of electricity, most of the time, the value of transmission losses is negative for power delivered compared with the rest of the EIM. **Figure 4.3** shows the market components for the EIM locational market price for Redmond, Washington, a city bordering Seattle, Washington. The orange line is the EIM average price and the blue indications that are mostly obscured by the congestion value are the whole price at Redmond. The components indicate the significant difference in wholesale electricity cost between the EIM average and Redmond, Washington. The average annual whole price for Redmond in 2019 was \$35.35/MWh. Average wholesale prices were collected for Pendleton, Oregon, as an indicator of eastside prices for electricity and for Bellingham, Washington, as well as three sites surrounding the Centralia coal plant in an effort to see if there were any congestion issues near the coal plant site. There were differences in the average annual Day-Ahead Market, but they were minimal and were near the Redmond price, indicating that in the Pacific Northwest prices across the region were not different enough to make a difference in where an SMR would be located. Other issues such as the relative cost of production would drive the siting decision.



Source: CAISO OASIS database

Figure 4.3. Components of the EIM wholesale price at Redmond WA ($/MWh).

4.3 Projections of Electricity Demand and Supply

The NPCC provides power plans that forecast future electricity demand and prices for the region. The NPCC (2019) power plan indicates that regional load growth was at 1.3 percent per year from 2015 through 2017. However, when abnormal winter temperatures were removed, load decreased 0.8 percent annually. The region's grid net load is forecast to grow to a nearly 25 GWe annual demand in 2038. Wholesale prices are expected to increase 2.2 percent in real terms from $23/MWh in 2019 to ~$35/MWh in 2038. In nominal terms, the price will be $51/MWh. The wholesale price increase for Washington could be higher if natural gas continues to be the marginal cost provider for power and the carbon tax is included. Other flexible renewable generation (discussed later) could ameliorate that price increase.

4.3.1 Adjustments to Future Market Projections

Coal retirements in Washington State will leave the state short of flexible power long before the first SMR can be built. All the coal generators at Centralia, Washington, will be closed by 2022. This could become the most critical issue for the combined generating fleet in the Pacific Northwest and the WECC. The closures will leave 1,342 MW of generation capacity missing from the generation mix even though the plants only operated at about 46 percent of capacity. With the cost of natural gas plus carbon tax increasing the cost of fossil generation, Washington's three types of natural gas generators will be

$60/MWh to $84/MWh more expensive than their direct cost due to the carbon tax, if utilities decide to use natural gas generators. They could also choose to purchase unbundled RECs.

A movement toward carbon-free transportation may affect the above forecast after 2038, because the potential for electric cars to replace internal combustion engines may be forced if the carbon taxes are placed on fossil transportation fuels. An ameliorating force may be the entry of affordable fuel-cell–driven vehicles. Several factors may drive the choice between hydrogen cars and electric vehicles (EVs). Currently, the infrastructure exists to charge EVs but the refueling infrastructure for hydrogen cars is limited. However, the drive range of EVs is short and recharge times are long. Yet, for short distance commutes, EVs can be charged at home overnight and can easily make it to work where charging infrastructure is being installed. Given that the basic electric infrastructure already exists, adding charging stations is a low-cost investment for most businesses.

Auto manufacturers are currently divided about whether to invest in EV or hydrogen-powered vehicles. A recent study by Horvath and Partners indicates that EVs are 70–80 percent efficient, while hydrogen vehicles are only 25–35 percent efficient. Fuel cell inefficiency is a part of the problem because of the 55 percent loss during drive train conversion (Edelstein 2020).

On the other hand, some proponents of fuel cells indicate the refilling time of a few minutes is an advantage relative to the long periods reported for batteries. In addition, most fuel cell vehicles have a drive range of 300 miles, whereas few, if any, EVs other than Teslas can make that range.

An electric car requires 34 kWh per 100 miles (DOE 2020). A companion document estimated the cost of energy per mile for EVs at different electricity costs. An EV with 3 miles/kWh (current technology) was estimated at $80/MWh prices, and the cost of energy/mile was about $0.03/mile (INL no date). Currently, fuel cell vehicles get between 57 and 68 miles/gasoline gallon equivalent (GGE; DOE 2020). The cost of hydrogen per mile is currently significantly higher than the cost of gasoline per mile but is expected to approach that of gasoline, but even that will still leave fuel cell cars at $0.11–$0.13/mile—significantly above the cost of EV costs per mile (Voelcker 2020). Washington retail prices are approximately $80/MWh on average, thus EVs are the best option especially outside of California. California has some infrastructure for hydrogen vehicles, whereas most of the remaining states have very little hydrogen refueling infrastructure. The question will be whether EVs can improve their recharging time and whether delivered renewable hydrogen cost can be driven low enough to compete with once-through electricity.

4.3.2 Impact of Moving to EVs on Electricity Demand

Davis et al. (2020) evaluated the impact of EVs on the Washington State electric grid. They assumed that 1 million light-duty vehicles (LDVs), 4,600 medium-duty vehicles, and nine charging hubs for heavy-duty vehicles would be charging in the electric grid. Under this assumed baseline, Puget Sound Energy had the highest unmanaged charging profiles at nearly 700 MWe followed by BPA at 600 MWe, with an overall total of 1.8 GWe of additional load in 2028. Electricity production costs increased 8 to 9 percent depending on the scenario and reached $56/MWh to $61/MWh for the state. The highest prices were in the Avista and Puget Sound Energy Balancing Authorities (BAs) where the prices ranged from $134/MWh to $178/MWh. The locational marginal prices (LMPs) ranged from $22.80/MWh in the baseline to $44.00/MWh with 1.8 million LDVs and to $111.31/MWh with 2.7 million LDVs in Washington.

Figure 4.4 indicates points of congestion given the penetration of EVs. The red lines with labels indicate the transmission lines that are congested. Congestion indicates the transmission line where the limits are being reached. Areas of congestion point to places where potential plants could be located to reduce that congestion on those transmission lines. The congestion points are in northwest Washington, south of

Custer and south of Boundary from the summer through winter. There are also congestion issues at Cross Cascade North during all seasons during peak hours. Another congestion point is at Echo Lake in the winter. Note the points south of Centralia at Paul-Allston and South of Allston. An SMR on the correct side of the congestion point could help reduce the congestion.

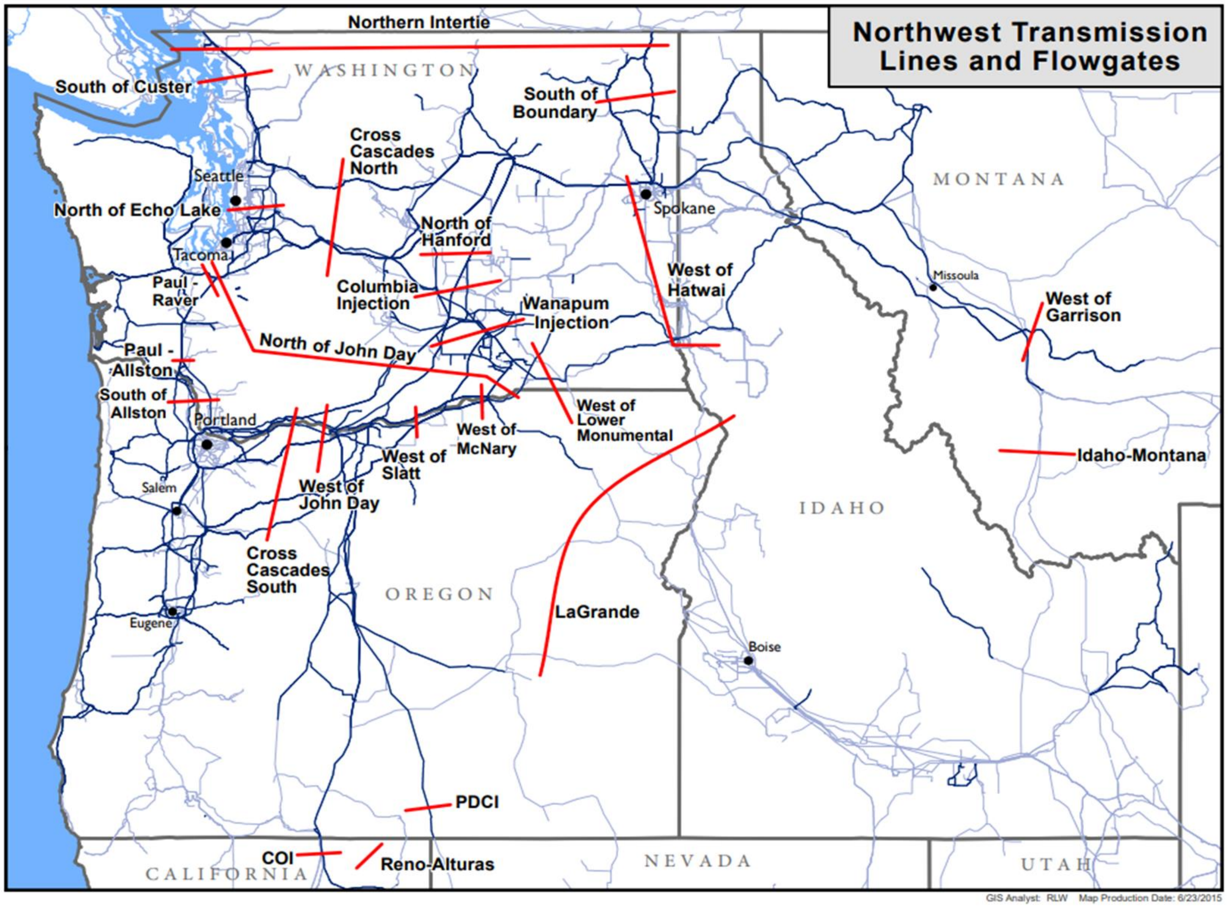


Figure 4.4. Congested lines (indicated in red)with EV penetrations.

4.4 Electricity Price Projections

According to the NPCC (2019) interim plan, real prices are likely to be around $35/MWh by 2038. The price in 2019 was $23/MWh and is expected to climb approximately 2.2 percent per year in real terms. With the likely joining of BPA and Western Area Power Administration (WAPA), 77 percent of WECC’s electricity demand will be delivered through EIM members. The wholesale Day-Ahead Market is considered an inevitability (Zichella 2019), although the EIM is a real-time balancing market. Thus, current LMP prices for the Day-Ahead Market may provide a hint of the differential between the two markets for future retail prices. Current wholesale EIM LMP prices were approximately $35/MWh—somewhat below what the estimated LCOEs are for the two reactors evaluated in this study.

5.0 Case Studies

This section introduces the approach to estimating the LCOE (Section 5.1) and presents the case studies for the (1) NuScale facility at INL, (2, 3) ENW Site 1 NuScale and GEH BWRX-300 options, and (4, 5) Centralia NuScale and GEH BWRX-300 options developed to evaluate the LCOEs for NuScale and GEH SMRs and presented in Section 5.2 in the order listed below.

- Case 1: NuScale Facility at Idaho National Laboratory
- Case 2: NuScale facility at ENW Site 1
- Case 3: GEH BWRX-300 at ENW Site 1
- Case 4: NuScale facility at coal plant site in Centralia Washington
- Case 5: GEH BWRX-300s at coal plant site in Centralia Washington.

Currently, there is little comparability in the LCOE estimates for the two SMRs being studied in detail. The differences in the result are related to the different levels of maturity for the two designs and cost estimate approaches. GEH is using a design-to-cost methodology with target pricing that is being confirmed as the design matures. NuScale's estimates are more mature than GEH's estimates. An estimate of the historical cost growth of mega-projects (both nuclear and non-nuclear by MIT [Buongiorno et 2018]) indicates that there was significant growth in the cost of the NuScale estimate between earlier and later estimates (**Figure 5.1**). The green lines indicate the projected change in costs as normal project cost estimates move from Class 5 to Class 1 to actual costs. At completion actual costs are 1.0. Costs can diverge either positively or negatively from the final cost of the project. If that trend continues the figure implies that NuScale's recent estimate is about 75 percent of what the projected actual cost for the FOAK plant will be. Improvements in the capacity of the individual module from 50 MW to 60 MW and a $450 million reduction in costs as a result of value engineering may have changed the calculation though. UAMPS provides a $55/MWh Power Purchase Agreement (PPA) cost at the beginning of this project for the UAMPS facility at INL. The value is heavily subsidized because the total project costs are currently estimated to be more than $6 billion because DOE is providing up to $1.4 billion in financing (DOE/NE 2020).

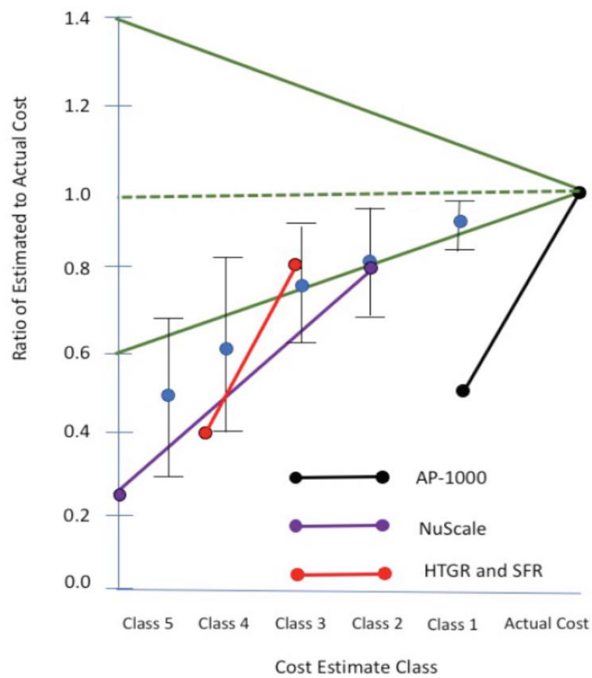


Figure 5.1. Cost change from conceptual design to completion for mega-projects as designs mature. (The blue data points are non-nuclear projects of similar complexity.) (Buongiorno et al. 2018)

As an additional caveat, the estimates for the LCOEs for NuScale and GEH in the case studies presented below will only have rough order of magnitude estimates for the pre-construction costs due to the lack of maturity in studies that indicate the cost of site preparation work that will need to occur to implement the two designs at the two Washington sites. In addition, the study appends the costs for second- and third-of-a-kind plants to the estimates for NOAK estimates provided by NuScale and GEH.

5.1 Approach to Estimating LCOE

Based on the cooperation of NuScale, GEH, ENW, and UAMPS, a basic approach was taken to estimating the LCOE in 2019$. The assumption was that NuScale and GEH would have good cost estimates given that they had the technical information and cost estimates in hand. A questionnaire was developed and completed to determine the basic components of the cost estimate, including the costs of pre-construction, construction, decommissioning, O&M, and fuel. The questionnaire also asked for capacity factors and efficiency percentages. NuScale, GEH, ENW, and UAMPS were asked for timelines for pre-construction and construction along with the weighted average cost of capital. The questionnaires provided were the same for NuScale and GEH. ENW and UAMPS received a different set of questions to determine the owner/operator costs above the cost estimates provided by NuScale and GEH to acquire a total cost of construction and operations. The two questionnaires are provided in Appendix A. UAMPS chose to provide a busbar cost for the NuScale facility, a FOAK facility, rather than provide the ownership and pre-construction costs.

A hybrid approach to calculating the total costs of installed capital was used. The timeline and spend curves were applied to the pre-construction, construction, startup, and initial fuel load costs, and the weighted average cost of capital was applied to determine the total installed cost of capital. The owner's costs and the interest during construction were used in the G4Econs model (Harrison 2018; Harrison et al. 2018) to detail the average spend rate to determine a more accurate installed cost of capital. The total installed cost of capital divided by the capacity of the plant provides the cost per kilowatt-hour. The G4Econs model provides this calculation. G4Econs was used to calculate the LCOE.

Neither GEH nor NuScale provided all the information requested in the questionnaires. Thus, cost bases were adjusted to make the two cost estimates similar but not comparable. For example, one estimate included the initial fuel load, the other did not; each provided decontamination and decommissioning costs, but in a slightly different form, although both were based on NRC calculation methods; neither included contingency, but the bases for being less than Class 1 estimates would indicate that some level of contingency should be included. A Reliable Fuel Supply model (Phillips et al. 2010) was used to calculate the missing initial fuel load for one plant. Rothwell (2004) was used to apply an appropriate contingency based on the class of estimate provided. However, even with adjustments, the two LCOEs are not be considered equivalent because the approaches taken toward the two estimates are totally different. One entity is basing its cost estimates on the designs, the other is deploying a design-to-cost strategy to meet a cost target. The different approaches to the cost estimate make them incomparable.

ENW will also have costs above those calculated by GEH and NuScale for pre-construction activities as well as O&M. Additional costs that ENW will bear if they build an SMR at Site 1 (also known as WNP-1) were estimated from a previous study. An ENW study performed by URS provided a basis for pre-construction and construction costs for a new site, and then calculated potential savings for use of Site 1, which already has an operating nuclear power plant (URS 2014a, 2014b). The costs for pre-construction and construction were escalated to 2019$ because they are in 2014$. Construction cost savings are deducted from the NuScale and GEH estimates.

In addition, ENW will be required to undertake a number of activities for licensing and permitting a new plant. ENW estimates that the overall cost of permitting a new plant and other owner's work will be approximately $200 million for the NOAK plant. The 2014 URS study indicated that ENW might be able to save $34 million on permitting a new plant because of work from the previous environmental impact statement (EIS) and report work done at Site 1. The Centralia site will not have that advantage.

NRC regulations require that an EIS be developed for siting new commercial power reactors. An EIS is required for a construction license under Title 10 of the *Code of Federal Regulations* Part 50 (10 CFR Part 50), or a combined operation license or early site permit under 10 CFR Part 52. NuScale is applying for a license under Part 52 and GEH is applying under Part 50 for the initial BWRX-300s. The EIS is based on an environmental report (ER) prepared by an applicant for an NRC license or permit that describes the environmental impacts of the proposed plant and reasonable alternatives. NEI reported increasing total costs of NRC reviews of early site permits; the PSEG Nuclear, LLC review cost more than $18M (NEI 2018). The costs to an applicant for the EIS phase of new plant licensing can be considered in three categories:

- Direct Cost to the Applicant: ER preparation and EIS support
- Fee recovery by NRC: NRC staff effort for EIS preparation and licensee interactions
- NRC sub-contractor support for EIS preparation.

The cost of the EIS is based on the need to fully characterize the site. Once the site characterization information is collected, the assessment steps are similar. In the vicinity of Site 1, the NRC recently completed a Supplemental EIS for the renewal of the CGS operating license. In addition, DOE prepares annual Site Environmental Reports for the Hanford Site. The differences in the environmental characteristics of the two sites are highlighted in **Table 5.1Table 5.1**. Comparison of the environmental characteristics at the proposed sites..

Table 5.1. Comparison of the environmental characteristics at the proposed sites.

Characteristic	WNP-1	Centralia
Infrastructure	Two offsite power sources. Access to barge transportation for large components.	Two offsite power sources. Existing rail access for coal delivery.
Land Use	New plant would be consistent with nearby land uses.	New plant would be consistent with previous land uses.
Water Use/Quality	Nearby water source (Columbia River) with an existing intake. Groundwater well characterized.	Water source and intake uncertain. Residual contamination from coal plant operations may affect groundwater.
Ecology	Well characterized site for ecological parameters.	Little characterization, but significant previous disturbance from coal plant operations.
Socioeconomics	Large local and knowledgeable operating workforce.	No local and knowledgeable workforce.
Cultural Resources	Previously developed site.	Previously developed site.
Air Quality	Good regional air quality, next to existing Columbia Generating Station.	Good regional air quality, proposed plant has fewer emissions than previous facility.
Radiological Health	Offsite doses for routing releases and potential accidents are assumed to be within regulatory limits.	Offsite doses for routing releases and potential accidents are assumed to be within regulatory limits.
Waste	Plant operation waste disposed in accordance with regulations.	Significant waste generation during coal plant decommissioning in preparation for new plant construction. New plant operation waste disposed in accordance with regulations.
Accidents	Located farther from large urban centers, 150 mi from Tacoma	Located closer to larger urban centers, 40 mi from Tacoma.

The NRC published resource estimates for licensing activities for the new reactor business line based on the costs of historical actions in April 2020 (NRC 2020a). According to the *Federal Register* (NARA 2020), the NRC currently charges $275/h for its services including development of an EIS; total costs for various new reactor activities are shown in **Table 5.2**. After adjustments for changes in the EIS process, $10 million is the estimated cost including ENW’s own work.

Table 5.2. NRC total cost for new reactors business line fee estimates (NRC 2020a).

	Staff Hours			Contractor Costs			Total Cost
Licensing Action	**Low Level of Effort**	**High Level of Effort**	**Average**	**Low Level of Effort**	**High Level of Effort**	**Average**	
License Amendments	30	1,819	263	N/A	N/A	N/A	$0.072
Combined Licenses (8 total)	44,269	178,160	89,261	$2.76M	$8.88M	$5.02M	$24.55M
Early Site Permits (6 total)	14,626	64,940	29,104	$1.87M	$5.11M	$2.76M	$8.00M
Design Certifications (6 total)	108,000	257,104	179,395	N/A	N/A	N/A	$49.33M

The O&M costs include a $65,000 per property lease at Site 1 and ENW will pay taxes annually. ENW is exempt from federal taxes (ENW 2018), but they will pay the Washington Privilege tax. They indicated that Site 1 will pay 2 percent of gross revenues plus 5 percent of the first 4 mills of value per kilowatt-hour and 5 percent of the first 4 mils of self-generated electricity. They also provided the Washington Privilege Tax value for a 720 MWe SMR at the Centralia site (based on RCW 54.28.20). ENW will also pay annual regulatory fees to the NRC (NRC 2020b). The annual fees have not been determined for SMRs, but the language in the regulation indicated that they will be apportioned by the megawatt-thermal of the reactor. Thus, the $4.7 million regulatory fee for large power reactors was apportioned by the megawatt-thermal of each of the reactors based on the average megawatt-thermal rating of the U.S. nuclear plant fleet. The calculations assumed an average of 3,600 MWt and a net efficiency of 30 percent. ENW will also pay insurance. Only one firm underwrites insurance for the nuclear industry, American Nuclear Insurers. A single unit reactor pays $1 million; the average for additional units is another $0.3 million or $1.3 million total (NRC 2019). In addition, ENW provided their overhead rates to apply to operating costs.

The Centralia site costs were based on the added costs for pre-construction. The Centralia site is the current site of Washington’s only coal-fired generation plants. The expectation is that the transmission hookups will be large enough to handle two NuScale plants or four GEH BWRX-300s. In addition, because TransAlta may be converting one of their coal plants to natural gas for the transition period to 2045, a brownfield site at one of TransAlta remediated sites will be used. The assumed site would pay $196,000/ac and construct a transmission line to the transmission access vacated by the one coal plant that will be removed.

The weighted average cost of capital (WACC) was assumed to be 4.3 percent, similar to ENW’s WACC, and was used for both plants. In addition, a 5 percent and 7 percent WACC was evaluated to analyze the effect of the change in interest costs on the LCOE. A sinking fund rate of 1 percent was based on the average treasury yields for long-term bonds, a lowest-risk approach.

ENW projected fuel costs from their 2019 annual budget were used to provide a range of fuel prices (**Table 5.3**) (ENW 2018). A $250/kgHM was assumed for standard fuel fabrication costs. An additional 25 percent surcharge was added to NuScale’s fabrication costs because the size of their fuel rods is unique.

Table 5.3. Nuclear fuel prices.

Year	Uranium $/lb$U_3O_8$	Conversion $/KgU UF_6	Enrichment $/SWU
2024	35.5	12.1	74
2028	44.5	11.2	80

SWU = Separative Work Unit.

Back-end fuel costs for 2 years of wet storage were assumed and the fuel would be placed in multi-purpose canisters casks and welded and placed on pads until a geologic depository or interim storage facility is built. ENW indicated the costs for their existing facility were about $9.3 million to $11.6 million. An alternative was explored based the cost basis report. The cost basis for cask estimates $120/kgHM (Shropshire et al. 2009) and were adjusted by the Handy-Whitman index to $160/$kg_{HM}$ (2019$). The 1 mill/kWh fee for final disposal was not included because it was suspended in 2013.[1]

5.2 Case 1: NuScale Facility at the Idaho National Laboratory Site

Case 1 evaluates whether the SMR power at INL proposed to be owned by the UAMPS could be cost beneficial to the state of Washington in meeting its power requirements in 2030 and 2045. UAMPS provided this study with a PPA price ($55/MWh [2018$]) for power delivered at the busbar of the plant. Thus, this case study only evaluated whether and exchange agreement would be preferable to the cost of pancaking associated with transporting power across three transmission territories.

The Carbon-Free Power Plant (CFPP) is a 720 MW NuScale LWR. The CFPP is located in PacifiCorp East (PAC East) territory and would need to be wheeled across PAC East and Idaho Power transmission areas to reach BPA's Balancing Authority Area (BAA) territory. For the power to reach Washington State, the power would either be wheeled to utilities in the state or obtained by using an exchange agreement with BPA, which provides power to most Washington State utilities.

Wheeling the power to utilities in Washington State meets the requirement of CETA, the Washington State law requiring carbon-neutral positions by 2030 and no carbon emissions by 2045. Wheeling would require transmission payments to transmission owners along the path to the utility, including PAC East, Idaho Power, and BPA. Each owner would add their transmission costs to the PPA price (called pancaking), thereby rendering more expensive power. The delivered cost would include the busbar quantity leaving the Idaho plant, any losses due to transmission, and all the delivery charges across all BAAs including any congestion revenue charges.

An alternative approach would be for UAMPS and BPA to undertake a power exchange, whereby UAMPS would deliver power to BPA's customers in Southern Idaho and BPA in turn would deliver an equivalent amount (MW) of power to UAMPS' customers in Washington State. A previous example provides an illustration of how the exchange would work. The South Idaho Exchange (SIE) was a power exchange agreement between PacifiCorp East and BPA. The exchange solved problems for both BAAs by allowing each BAA to serve the other's loads by exchanging power. PAC East had load obligations in PAC West in Oregon and Washington. The loads were wheeled a long distance from their generators located in Wyoming and Utah to Oregon and Washington. This forced PAC East to pay transmission charges from Wyoming to Oregon and Washington, including the transmission charges. BPA also had customers in Southeast Idaho, far from their supply, called the Federal Columbia River Power System in Oregon and Washington. This forced them to pay the transmission charges to their customer in Southeast

[1] National Association of Regulatory Utility Commissoners v. U.S. Department of Energy, No. 11-1066 (D.C. Cir. Nov. 19, 2013)

Idaho. The two entities' solution was the SIE agreement, which ended in 2016 (BPA 2018), that eliminated the cost of wheeling federal power across the Idaho Power and PacifiCorp transmission systems to Southeast Idaho utilities. Without the SIE, BPA is using wheeling of public power and providing supplemental purchases of power from the market. In the long-term, BPA is evaluating whether power could be provided beneficially through a new transmission line or some other solution.

As a part of the study, UAMPS proposed that an alternative delivery approach like the SIE be explored. The parties involved would include the BPA, UAMPS, and Washington State utilities. In this proposed agreement, UAMPS would agree to deliver an equivalent amount of power to BPA's customers in Southeast Idaho, while BPA would provide the equivalent amount of power to the CFPP's utility customers in Washington State. The exchange would provide two benefits to BPA. First, it would provide supply for BPA's customer obligations in Southeast Idaho without the additional wheeling charges. Second, it would remove the need for BPA to build a transmission line to Southeast Idaho, which could cost \$1.5 to \$2.0 million per line mile.

The question is whether the UAMPS-BPA exchange agreement would meet the requirements of CETA. Currently, BPA's annual mix of sales is essentially 88–97 percent carbon free. Because BPA purchases electricity from the grid the exact mix of BPA's generation is unknown. The range occurs as a result of the variability in the Columbia River system streamflow (BPA 2019a).

The exchange approach, if all the requirements were met including the CETA rules, indicates the delivered electricity would save significant delivery charges to a Washington utility. A study by Chang et al. (2016) indicated three additional charges above the transmission charges[1] would be added to the cost of delivered electricity. If the delivery point in Washington were outside of BPA's territory, the additional charges would include delivery through BPA, Idaho Power, and Pacific Corp territories (see **Table 5.4**). The pancaking charge for wheeling would increase the cost by \$11/MWh, driving the cost up to \$66/MWh to deliver electricity from a NuScale SMR located at INL. If the total dispatch hurdle, which includes administrative transmission tariff charges, is included, the cost rises an additional \$3/MWh to \$69/MWh. The additional commitment hurdle and bilateral trading margin is a savings from entering the EIM and so the commitment hurdle would not be incurred. By selling through an exchange agreement, additional savings would be derived from the reduction of the wheeling charges and administrative transmission tariff charges for two of the three BAAs. Thus, by selling through an exchange agreement, UAMPS could deliver power at approximately \$60/MWh as opposed to at \$69/MWh. Thus, using the EIM, rather than bilateral trading, could provide electricity that is \$20/MWh cheaper because two of the three BA charges in **Table 5.4** would be eliminated; only the delivering BA charge would be included.

Table 5.4. Added costs of delivering power from INL (\$/MWh).

	Wheel Charge	Wheel Charge + Dispatch Hurdle	Wheel Charge + Dispatch Hurdle + Commitment Hurdle and Bilateral Trading Margin
BPA	4.3	5.3	11.4
IPCO	3.2	4.2	10.3
PACE	3.75	4.75	10.85
Total	11.25	14.25	24.35

[1] Transmission charges include charges for administrative, market friction, and trading margin.

5.3 Energy Northwest Site 1

ENW is expected to be the owner/operator for an SMR at Site 1. According to ENW, they obtained a URS report in 2014 that said they could reduce costs substantially for the site. That study reported approximately $30 million (2014$) could be saved in licensing costs. The biggest cost savings in the licensing process involve the following activities in which all or a portion thereof may be reduced substantially if we could base much of it on what was completed in the past. The costs and benefits that would accrue to an ENW facility at Site 1 are listed below.

- Final Safety Analysis Report development (required by 10 CFR 52.79)
  - seismic characterization
  - geologic characterization
  - hydrologic characterization
  - meteorological characterization
  - assessment of nearby facilities, hazards, population
- Siting assessment (required by 10 CFR 52.79(a)(1) and 10 CFR 100) in addition to that needed for the Final Safety Analysis Report
  - features having a significant bearing on accident (probability/consequence)
  - underground structure and history
  - underground tectonic structures and effects of manmade activities
  - evaluation of past earthquakes on site
  - ground properties
  - historical earthquakes affecting the site
  - nearby earthquake epicenters
  - determination of capable faults within 200 miles
  - required investigation for surface faulting
  - required investigation for seismically induced floods and water waves
  - seismic and geologic design bases
    - safe shutdown earthquake
    - operating basis earthquake
- ER (required by 10 CFR 50.30(f) and described in NRC Regulatory Guide 4.2 (NRC 2018)
  - land use
  - water resources
  - ecological resources
  - socioeconomics
  - environmental justice
  - historical and cultural resources
  - air resources
  - nonradiological health
    - public and occupational health
    - noise
    - transportation
    - electromagnetic fields
  - environmental impacts from construction
    - environmental impacts from operation
    - fuel cycle, transportation and decommissioning impacts
    - cumulative impacts

  - environmental impacts of alternatives
- energy alternatives
- site alternatives
- design/system alternatives.

In addition, the URS (2014a and 2014b) study indicated that because Site 1 was 65 percent finished when work stopped at the site and that the remaining structures were in good shape, they could be used for the construction of an SMR. The study indicated that nearly $140 million (2014$) could be saved. The costs and benefits that would accrue to an ENW facility at Site 1 are listed in **Table 5.5**. The remaining amount of savings would be due to a 1-year savings related to the shortened project schedule.

Table 5.5. A list of savings from Site 1 derived from using previous plants' remaining structures ($000 2014$).

	Account Description	Factory Cost	Labor Cost	Material Cost	Total Cost	Credits
211	Yardwork	570	20,138	15,080	35,788	17,733
218B	Administration and Service Building	1,184	5,343	4,312	10,839	3,252
218D	Fire Pump House	57	362	260	679	679
218L	Technical Support Center	78	723	408	1,209	1,028
218S	Wastewater Treatment Center	13	683	459	1,155	1,039
214	Security Building	78	1,395	616	2,090	1,672
216	Waste Processing Building	983	14,244	8,089	23,316	11,658
242	Station Service Equipment	37,767	2,890	533	41,191	1,978
243	Switchboards	2,918	646	253	3,818	998
244	Protective Equipment		4,504	3,879	8,383	507
252	Air, Water and Steam Service Systems	11,725	21,853	7,601	41,179	10,361
253	Communication Systems	3,222	6,999	1,124	11,345	7,434
254	Furnishings and Fixtures	3,993	981	132	5,105	1,855
255	Wastewater Treatment Equipment	1,425	3,661	396	5,482	5,207

The study also indicated the plant would take one less year to complete because of all the items already in place. Both GEH and NuScale plants had 1 year of construction removed.

5.3.1 Case 2: NuScale at the Energy Northwest Site 1

According to the agreements with NuScale and GEH only the LCOE will be published. At approximately $51.02/MWh over a 40-year operational period (see **Table 5.6**), the NuScale costs at ENW Site 1 are lower than the $55/MWh provided by UAMPS for the INL site; the former is the comparative baseline value assuming a 4 percent WACC, 30 percent efficiency, and a 95 percent capacity factor. The value in every table in this section is compared against the $51.02/MWh. The Site 1 facility would benefit from previous EIS and licensing efforts, from facilities and infrastructure built for the Site 1 reactor that was never completed, and from a 1-year reduction in the construction time. Thus, estimates for other sites may be higher depending the benefits of the site.

Different levels of the WACC were considered as part of the analysis, including evaluated costs at 3, 4, 5, 6, and 7 percent. The 3 and 5 percent WACC levels provide a bounding level for organizations such as ENW. The 7 percent real rate reflects the LCOE at an the IOU's real rate. Note that the interest rate increase of 1 percent adds more than $5/MWh and that the effect of compounding adds $7/MWh between 6 percent and 7 percent weighted average costs of capital.

The effects of a lower fuel cost using an MIT value of $6.00/kgU[1] for conversion rather than the $11.20/kgU that ENW was forecasting for 2028 were evaluated. We also lowered the prices for uranium and enrichment to the ENW 2024 prices of $35.5/lb of U_3O_8 and $74/Separative Work Unit (SWU). The change in fuel cost decreased the LCOE by $0.59/MWh from the baseline value of $51.02. This further emphasizes how little fuel costs influence the overall LCOE.

Table 5.6. NuScale's LCOEs at Site 1 for different real interest rates for the WACC ($/MWh).

	Interest Rate				
LCOE	3% WACC	4% WACC	5% WACC	6% WACC	7% WACC
$/MWh (2019$)	46.20	51.02	56.40	62.35	68.83

The project length affects the LCOE through the added costs of interest during construction. The added interest costs approximately $2/MWh as the project length balloons by 4 years. Although only the project length was increased, typically the construction costs increase as annual fixed overhead accumulates (**Table 5.7**).

Table 5.7. Project length at Site 1 ($/MWh).

	Project Length					
LCOE	4 years	5 years	6 years	7 years	8 years	9 years
$/MWh (2019$)	50.41	51.02	52.27	52.27	52.92	53.58

Table 5.8 illustrates the impact on LCOE of extending the operating length from 40 years to 100 years, assuming that financing is based on the operating period. Although costs decline to $44/MWh from about $51/MWh, most plants will be financed for 40 years or less. The value for 100 years provides the average cost across the operating period. Once the plant is financed the 40 years cash costs will decline dramatically.

Table 5.8. Operational period length at Site 1 ($/MWh).

	Length of Operations			
LCOE	40 years	60 years	80 years	100 years

[1] Personal communications with Jacopo Buongiorno, August 28, 2020.

$/MWh (2019$)	51.02	46.07	44.44	44.38

Operating efficiency is a key factor in determining the busbar cost of energy.[1] **Table 5.9** provides the cost per megawatt-hour as the operational efficiency changes from 28 percent to 32 percent. The operational efficiency will also decline as the turbine bypass is used to allow load. The LCOE declines from $52.5/MWh (28 percent) to $49.7/MWh (32 percent).

Table 5.9. Impact of improving operating efficiency at Site 1 ($/MWh).

	Operating Efficiency				
LCOE	28% Efficient	29% Efficient	30% Efficient	31% Efficient	32% Efficient
$/MWh (2019$)	52.48	51.72	51.02	50.36	49.74

The capacity factor is illustrated over a range from 85 to 95 percent in **Table 5.10**. At the 85 percent level the cost impact is almost $4.5/MWh more than the baseline value. Capacity factor evaluations may be important if the facility is to enter the regulation markets where capacity may be purchased but not used. The result also indicates that a decrease to 90 percent would incur approximately a $2.5/MWh increase in the LCOE.

Table 5.10. Impact of different capacity factors at Site 1 ($/MWh).

	Capacity Factor		
LCOE	85%	90%	95%
$/MWh (2019$)	56.46	53.59	51.02

The value of electricity from a NuScale plant may be enhanced if they can take advantage of two revenue stream enhancements: the value of peak hour prices that wind and solar may not be able to take advantage of and the ability to provide ancillary services. Because the NuScale plant can provide electricity for both peak-price hours and off-peak hours, the average revenue value should be above the system average. While the average price for the WECC indicates an average yearly price for all generation of $26/MWh, **Figure 5.2** indicates a significant difference between off-peak hours and on-peak hours projected in BPA’s rate proceedings. The unweighted average difference of $5.81/MWh indicates that an SMR could earn significantly more revenue than an intermittent technology that may or may not produce during on-peak hours. The weighted average is worth about $3.7/MWh above the average price of the Mid-Columbia Exchange.

[1] Operating efficiency refers to the conversion of thermal energy to electricity.

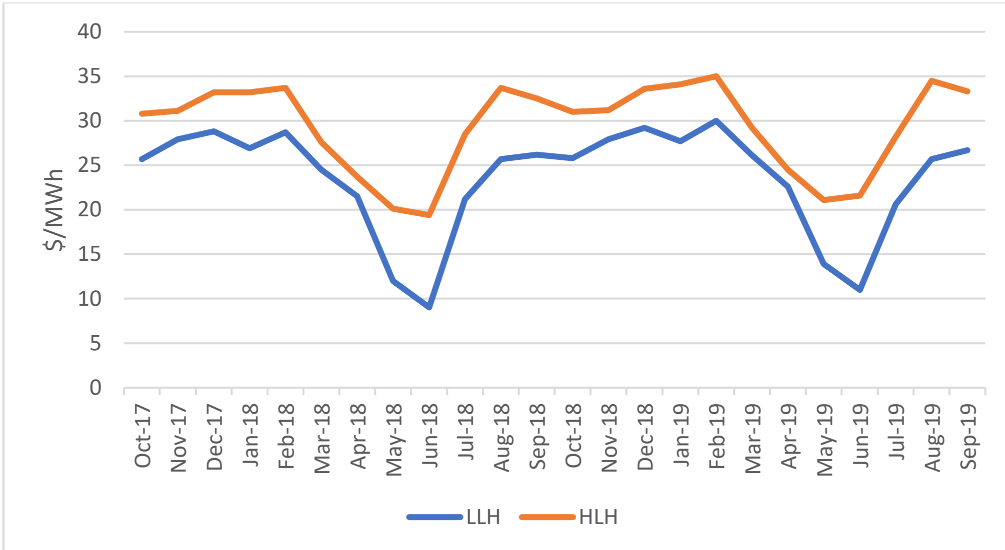


Figure 5.2. Prices by month BPA rate proceeding for Light Load Hour (LLH) and High Load Hour generation (HLH) (BPA 2016).[1]

Ancillary services may add revenue for ENW's NuScale plant. According to NuScale's assessment of their capability to meet ancillary service requirements, they may be able attain revenue in the load-following, regulation markets, and reactive power markets. They may also be able to earn black start revenue from utilities that need that service. According to NuScale, the Electric Power Research Institute (EPRI) provides guidelines for meeting load-following requirements, which the NuScale plant meets. The requirements require the plant to be capable of automatic frequency response. **Figure 5.3** provides an example of the NuScale load-following capability based on a typical electrical demand (Ingersoll et al. 2015). Load following allows the BA to meet demand and cover the difference between demand and variable renewable energy generation by having a generator that can fill the gap between the intermittent generation and grid demand.

[1] Light Load Hours is BPA's reference to the period when demand is lower and would be similar to off-peak demand, while High Load Hour is similar to peak demand or the hours when the highest demand occurs on the grid.

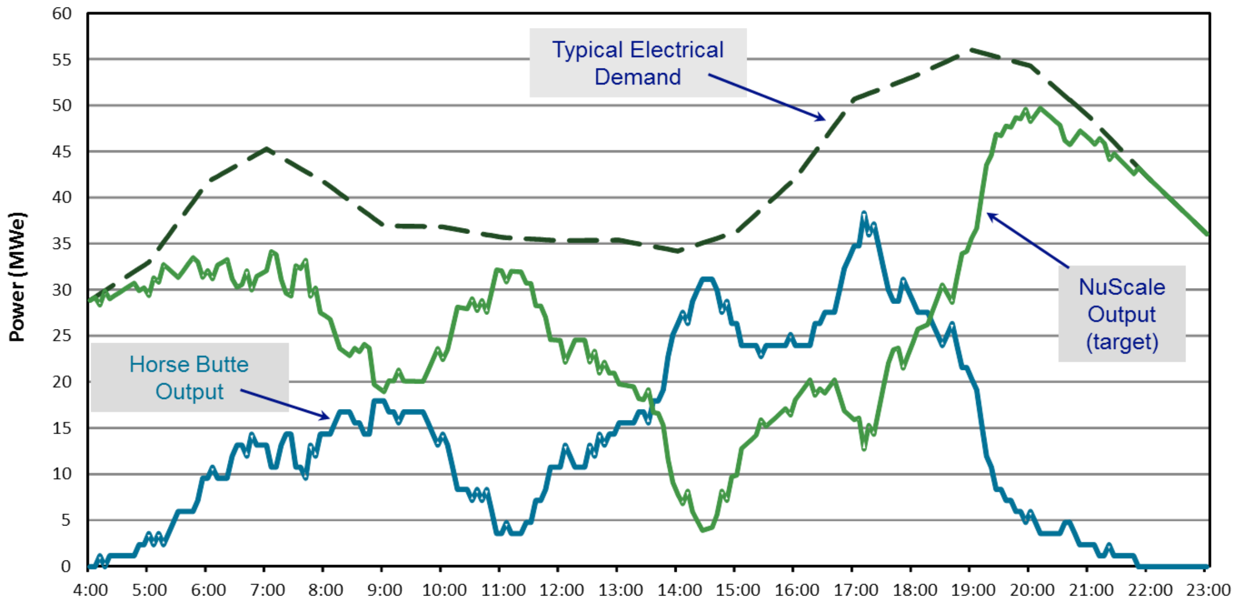


Figure 5.3. Example of NuScale plant load-following capability. The graphic indicates how well the NuScale plant can follow demand and meet the gap between Horse Butte (wind project) and demand.

The NuScale plant has three methods of providing flexibility: turbine bypass, reactor power change, and module dispatch (see **Table 5.11**). The NuScale plant is designed to meet the following requirements (Colbert 2019):

- Turbine bypass – capable of supporting 100 percent reactor thermal power while bypassing steam to the main condenser. Full turbine bypass capability allows a module to lower its output rapidly by diverting a portion of the main steam flow to the condenser, thereby further enhancing the plant's ability to respond to rapid changes in electrical grid demand without affecting reactor operation. This feature could be used to adjust output during periods of particularly high load or supply variation.
- The plant shall be capable of a 10 percent step change within 10 minutes to support stable grid operations.
- The plant shall have the capability of automatic frequency response on one operating generator within a ±2.5 percent control band.
- Reactive loading[1] capabilities were scheduled to be complete by June 2020.

Thus, the NuScale plant should be able meet the California Independent System Operator (CAISO) requirement of a 25 percent ramp-up in 15 minutes if their ramp of 3 percent per minute is linear and not an average.

[1] Reactive load refers to an out-of-phase AC system and is measured as Volt Amperes reactive (VAr).

Table 5.11. NuScale flexibility capabilities (Colbert 2019).

Method	Up Power	Down Power
Turbine Bypass	20% to 100% 27 minutes 3%/minute	100% to 20% 8 minutes 10%/minute
Reactor Power Change	20% to 100% 96 minutes 50%/hour	100% to 20% $\leq$ 24 minutes 200%/hour
Module Dispatch	HSD to 100% 13 hours Refueling	100% to HSD 30 minutes 200%/hour

HSD = Hot Shutdown.

BPA provides ancillary services to their customers as an additional charge to the delivered electricity. However, there is no wholesale market in the Pacific Northwest for ancillary services. BPA's priority firm power rate along with the demand charge rate are shown in **Table 5.12** (BPA 2019c). The rates indicate BPA's cost to deliver. Thus, the value to a generator providing these services would be somewhat less. BPA's load following includes a load-shaping charge. The load-following charge comprises two of three charges: a load-following charge, a demand charge, and a load-shaping charge.

Table 5.12. Priority firm power rate and demand charges (BPA 2019c).

	Energy Rate ($/MWh)		Demand Rate ($/kW)
Month	**HLH**	**LLH**	**HLH**
October	39.03	34.07	11.42
November	40.38	37.03	12.07
December	43.28	38.75	13.45
January	40.43	34.4	12.1
February	39.55	34.47	11.66
March	34.38	31.3	9.19
April	33.17	29.59	8.61
May	26.9	21.74	5.6
June	25.71	16.87	5.04
July	36.64	30.5	10.27
August	40.43	35.4	12.1
September	40.05	35.17	11.91

BPA's load-following rate is as follows (BPA 2019c):

- Customer Rate = ($1,980,553 * TOCA) composite and (-200,365) * TOCA for non-slice customers
- TOCA = Fiscal year Individual M High-Water Mark/Total fiscal year high-water mark.

A load-following customer will also pay the demand charge listed in **Table 5.13** (BPA 2019c). The load-shaping charge is shown in **Table 5.13**. The load-shaping billing determinant is based on the portion High Load Hour (HLH) and Light Load Hour (LLH) portion for each month and the number of actual load kilowatt-hours minus the shaped load in kilowatt-hours. The load-shaping charge can be positive or negative depending on whether the billing determinant for load shaping is positive or negative.

Table 5.13. BPA load-shaping rate.

Month Rate in mills/kWh	HLH ($/MWh)	LLH ($/MWh)
October	23.84	18.88
November	25.19	21.84
December	28.09	23.56
January	25.24	19.21
February	24.36	19.28
March	19.19	16.11
April	17.98	14.4
May	11.71	6.55
June	10.52	1.68
July	21.45	15.31
August	25.24	20.21
September	24.86	19.98

Transmission charges are the net of transmission costs and the BPA formula transmission rate is dependent on the type of transmission, the distance, and whether energy is crossing 230 kV lines or lines less than 230 kV (see **Table 5.14**) (BPA 2019b). The rates are calculated each quarter based on the Ancillary and Control Area Service Rates - ACS-20 Reactive and Voltage Control requirement ($1.726/kW/month +1 and multiplied by the sum of the main and secondary charges). Assuming there is no reactive power issue, it is just the sum of main and secondary charges. The rate for Site 1 would be approximately $2.1/MWh charge.

Table 5.14. Base transmission rates for main and secondary systems.

	Main Grid Charges	Rate
1	Main Grid Distance	$0.0729 per mile
2	Main Grid Interconnection Terminal	$0.76kW
3	Main Grid Terminal	$0.84/kW
4	Main Grid Miscellaneous Facilities	$4.16/kW
	Secondary System Charges	
1	Secondary System Distance	$0.7173 per mile
2	Secondary System Transformation	$7.84/kW
3	Secondary System Intermediate Terminal	$3.03/kW
4	Secondary System Interconnection Terminal	$2.14/kW

5.3.1.1 Conclusions for NuScale at Site 1

With the value of electricity on the Mid-Columbia Exchange averaging approximately $23/MWh, and expected rise to $35/MWh (see Section 4.4.1) according to the Northwest Power Plan, and if this is the market price to compete with before 2030, the NuScale plant would require about a $16/MWh subsidy for

ENW to break even in the baseline case ($51.02/MWh) if the market value is the cost of the competition. If nuclear power is the only non-emitting dispatchable resource, the penalty for emitting resources ($60/MWh, see Section 4.3.1) makes it cost competitive with NGCC at $36.61/MWh, which including the penalty would cost $96.61/MWh after 2029.

Perhaps with the EIM expanding to include most of the state of Washington there will be a wholesale market by the time the NuScale plant is built. If the CAISO wholesale market is expanded to the region the value of ancillary services might be met by the NuScale plant. Regulation Up prices varied between $2.88/MWh to $6.86/MWh while Regulation Down prices varied between $3.03/MWh to $5.29/MWh. The prices for these services appeared to decline over the collection period from 2009 to 2014 (Zhou et al. 2016). These prices are above the cost of the energy. Thus, the NuScale plant could earn as much as $35/MWh for energy and add on the ancillary services value if a wholesale market opened in the future for this product before 2029.

Thus, given the CETA charges for NGCC generation of $60/MWh, a NuScale plant at Site 1 should be a competitive resource if there are no other firm resources after 2029.

5.3.2 Case 3: GEH BWRX-300 at the Energy Northwest Site 1

The GEH BWRX-300 and NuScale LCOEs are not intended to be directly compared in this study. GEH is using a design-to-cost methodology with target pricing that is being confirmed as the design matures. NuScale's estimate is based on the current design. According to the agreements with GEH only the LCOE will be published. The GEH BWRX-300 at Site 1 provides an LCOE of $43.98/MWh based on **Table 5.15** at the 4 percent WACC. This is the comparative value in every table. However, some factors favor the GEH BWRX-300 at Site 1 over the Centralia site, which is discussed later. As noted above, there are about $300 million in savings for building at Site 1. The facility will benefit from previous EIS and licensing efforts reducing the cost by approximately $30 million, from facilities built for the Site 1 reactor that was never completed, and the remaining 1-year reduction in the construction time. Thus, estimates for other sites may be higher depending on the benefits of the site.

As a part of the analysis we evaluated the different levels of the WACC including evaluating costs at 3, 4, 5, 6, and 7 percent. The 3 and 5 percent WACC levels provide a bounding level for organizations such as ENW. The 7 percent real rate reflects the LCOE at an the IOU's real rate. Note that the interest rate increase of 1 percent adds more than $4.00/MWh and that the effect of compounding adds $5.20/MWh between 6 percent and 7 percent.

We also evaluated the effects of a lower fuel cost using an MIT value of $6.00/kgU for conversion rather than the $11.20/kgU that ENW was forecasting for 2028. We also lowered the prices for uranium and enrichment to the ENW 2024 prices of $35.5/lb of U_3O_8 and $74/SWU. The change in fuel cost decreased the LCOE by $0.59/MWh from the $43.98/MWh level, which we are considering the expected price. This further emphasizes how little fuel costs influence the overall LCOE.

Table 5.15. GEH BWRX-300's LCOEs at Site 1 for different real interest rates for the WACC ($/MWh).

	Interest Rate				
LCOE	3% WACC	4% WACC	5% WACC	6% WACC	7% WACC
$/MWh (2019$)	40.60	43.98	47.69	51.72	56.06

The project length impacts the LCOE through the added costs of interest during construction. The added interest costs approximately $2/MWh because the project length balloons by 5 years. Although only the project length was increased, typically the construction costs increase as annual fixed overhead accumulates (Table 5.16).

Table 5.16. Project length at Site 1 ($/MWh).

	Project Length					
LCOE	4 years	5 years	6 years	7 years	8 years	9 years
$/MWh (2019$)	43.98	44.40	44.83	45.18	45.73	46.20

Table 5.17 provides the impact on LCOE of extending the operating length from 40 years to 100 years. Although costs decline to $38/MWh from just less than $44/MWh, most plants will be financed for 40 years or less. GEH indicated they are planning for their plant to operate for 60 years as the base case. The value for 100 years provides the average cost across operating periods. Once the plant is financed, the cash costs above 40 years will decline dramatically.

Table 5.17. Operational period length at Site 1 ($/MWh).

	Length of Operations			
LCOE	40 years	60 years	80 years	100 years
$/MWh (2019$)	43.98	42.74	38.50	37.72

Operating efficiency is a key factor in determining the busbar cost of energy. **Table 5.18** provides costs per megawatt-hour as the operational efficiency changes from 28 percent to 32 percent. The operational efficiency will also decline if load following is to be undertaken. The LCOE declines from $48/MWh (28 percent) to $44/MWh (32 percent).

Table 5.18. Impact of improving operating efficiency at Site 1 ($/MWh).

	Operating Efficiency				
LCOE	28% Efficient	29% Efficient	30% Efficient	31% Efficient	32% Efficient
$/MWh (2019$)	47.90	46.98	46.11	45.31	43.98

The capacity factor was evaluated from 85 to 95 percent (**Table 5.19**). At the 85 percent level the cost is more than $5/MWh—more than at 95 percent. Capacity factor evaluations may be important if the facility is to enter the load-following markets where steam must be unused to meet load-following requirements. The result also indicates that a decrease to 90 percent would increase the LCOE by almost $3/MWh.

Table 5.19. Impact of different capacity factors at Site 1 ($/MWh).

	Capacity Factor		
LCOE	85%	90%	95%
$/MWh (2019$)	48.62	46.17	43.98

The value of GEH BWRX-300's electricity may take advantage of two revenue stream components: the value of peak hour prices that wind and solar may not be able to take advantage of and the ability to provide ancillary services. Because the GEH BWRX-300 can provide electricity for both peak-priced hours and off-peak hours the average revenue value should be above the system average. While the average price for the WECC indicates an average yearly price for all generation of $26/MWh, **Figure 5.2** indicates a difference between off-peak hours and on-peak hours projected in BPA's rate proceedings. The unweighted average difference of $5.81/MWh indicates that an SMR could earn more revenue than an intermittent technology that may or may not produce during on-peak hours. The result is an additional $3.7/MWh relative to the average of the market.

Ancillary services may add revenue for ENW's GEH BWRX-300. The BWRX-300 has a power maneuvering rate of 0.5 percent per minute between 50 percent and 100 percent of rated power. Their base design provides for a condenser bypass capability of 20 percent, which reduces power quickly on the steam turbine/generation of approximately 20 percent and allows the reactor power to "catch up" with the steam turbine/generator side over time. Additional condenser bypass capability up to 100 percent can be added as an option.

Based on the information received from GEH, only load-following ancillary services for BPA-type organizations can be assumed with the standard configuration, which provides 7.5 percent in 15 minutes without steam bypassing the turbine and being dumped into the condenser. An optional configuration would allow for additional steam bypass and achieve the CAISO Regulation Up or Regulation Down requirements of a 25 percent up and down rate over 15-minute intervals to qualify for those ancillary services (CAISO 2018). CAISO does not have another load-following product that allows for slower response.

5.3.2.1 Conclusions for GEH BWRX-300 at Site 1

With the value of electricity on the Mid-Columbia Exchange averaging approximately $23/MWh and expected to rise to $35/MWh (see Section 4.4) in real terms and if this is the market price to compete with before 2030, GEH BWRX-300 would require about a $8.9/MWh subsidy for ENW to break even in the baseline case ($43.98/MWh). If nuclear power is the only non-emitting dispatchable resource, the penalty for emitting resources ($60/MWh, see Section 5.3.1) makes it cost competitive with NGCC at $36.61/MWh, which including the penalty would cost $96.61/MWh after 2029.

Perhaps with the EIM expanding to include most of the state of Washington, there will be a wholesale market by the time the GEH BWRX-300 is built. If the CAISO wholesale market is expanded, higher prices may be obtained because the system-wide price is provided to all entities providing energy. Ultimately, the competitiveness of nuclear power will be dependent on the quantity and quality of other firm power generators. Thus, given the CETA charges for NGCC generation of $60/MWh, a GEH BWRX-300 at Site 1 should be a competitive resource after 2029.

5.4 Coal Plant Site in Centralia Washington

The project team chose the TransAlta Centralia plant site preliminarily as site for a potential nuclear plant when it was believed that both coal fire plants at the site were going to be dismantled by 2025. The preliminary choice was made because ENW had preliminary discussions with TransAlta. In addition, the site had advantages such as having transmission interconnection infrastructure in place if the coal plants were completely dismantled. Also, there are transmission congestion issues to the south of the plant and a new nuclear plant would maintain or reduce the congestion issues at current levels. In addition, the nuclear plant would be closer to load centers in Seattle, Tacoma, and Olympia than a plant located in Richland Washington. If the coal plant is not converted to gas-fired generation, a nuclear plant would replace lost jobs with about the same salary ranges or slightly higher for nuclear operators (Glassdoor 2020).

There are two coal-fired plants at the Centralia site (~10 mi northeast of Centralia, Washington) with a capacity of 1,340 MWe. The plant began operations in 1971 and both coal plants are expected to be no longer generating by 2025 (NPCC 2019). The plants are operated under a long-term contract and produce 10 percent of Washington's electric power. The site has 7,155 acres of land, 2,000 of which have been reclaimed. Thus, there is more than enough area to site a NuScale facility at this location (TransAlta 2018). **Figure 5.4** provides an aerial photo of the site. The coal-fired plants sit on more than 150 acres if the surge pond, coal pile, and buildings are included. There may be more conducive sites for a NuScale plant in some of the TransAlta's coal mining sites at Centralia. One site alone is more than 800 acres (**Figure 5.5**). The site easily accommodates the emergency protection zones of the NuScale plant.

Figure 5.4. Aerial view of the Centralia coal fire plants. (Graphic obtained from Google Earth.)

Figure 5.5. TransAlta coal mining site. (Graphic obtained from Google Earth.)

The Centralia site sits near a seismically active area (**Figure 5.6**). The NuScale facility, however, is designed to safely ride through a significant seismic event. The plant is designed to accommodate input spectra with frequencies ranging from 3 to 12 Hz and peak ground accelerations of 1.15 g (NuScale 2020).

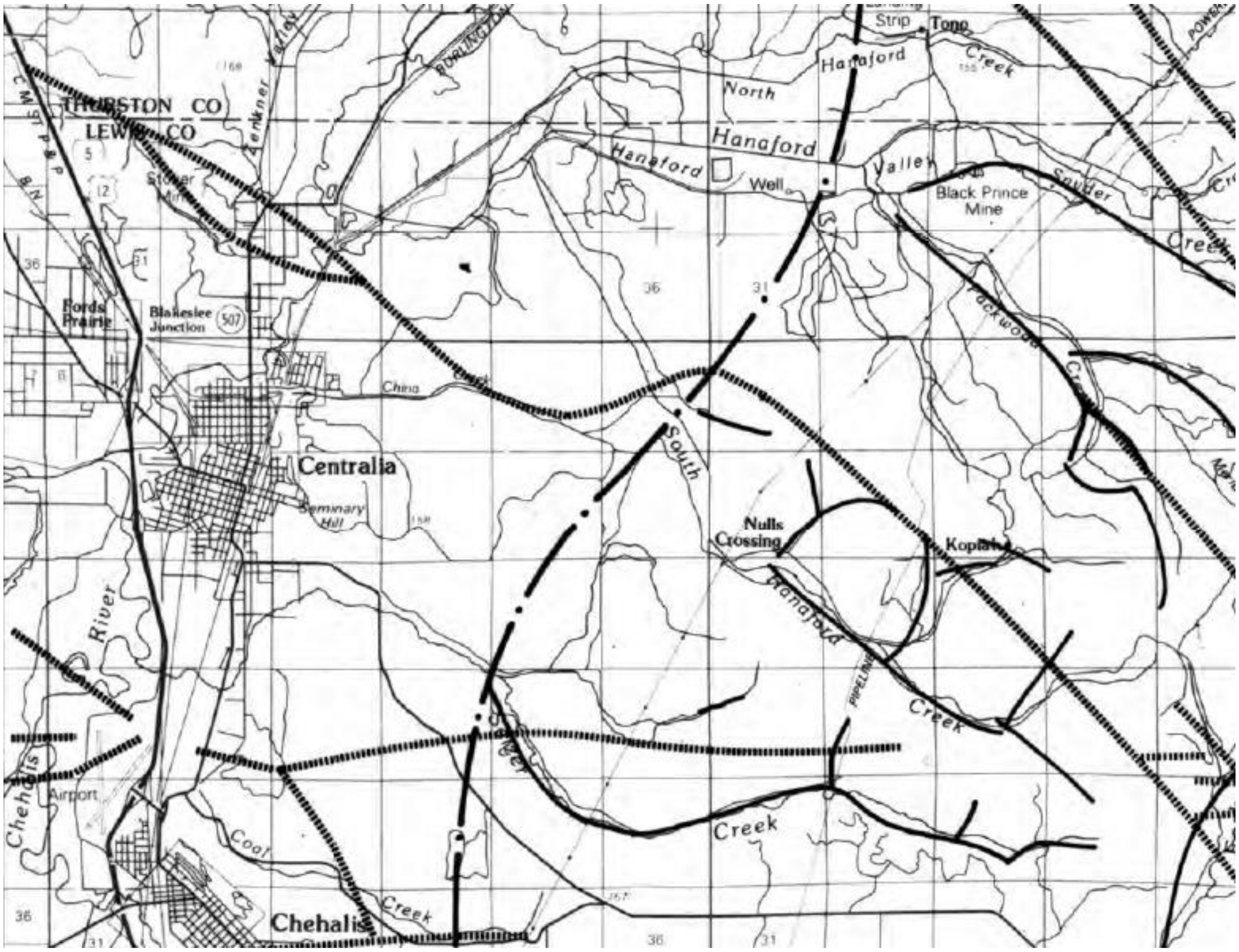


Figure 5.6. Seismic map of the Centralia area. The lines indicate faults (DNR 1981).

TransAlta had planned on conducting discussions with ENW but the COVID Pandemic delayed those plans. At the time of this study's inquiry, TransAlta had made no decision about its plans for the site once the coal plant generation is complete. Their current plans appear to be focused on converting the remaining coal-fired plant to gas-fired generation for the period from 2025 to 2045. They are hoping to find enough subscribers to pay for the plant. There is plenty of acreage for the plant but not at the current site of the soon-to-be converted coal-fired plant. Thus, two alternatives are being evaluated for both GEH and NuScale: (1) if both plants are demolished by 2025, multiple nuclear units would be added; and (2) if one coal plant is converted to natural gas, the nuclear facility would be constructed on one of the brownfield sites nearby and would use the transmission interconnection vacated by the demolished coal plant. For Alternative 1, the full costs of pre-construction and construction as well as the original time for construction were used. For O&M costs, the average cost of insurance for multiple plants was used to reduce the $1.3 million charged for multiple reactors at the same site. For Alternative 2, the full costs of pre-construction and construction, without the Site 1 savings, are included. The NuScale SMR and GEH BWRX-300 would require an additional cost to connect to the decommissioned coal-fired plant transmission interconnection. The transmission line costs are estimated to be more than $1 million/mi (E3 2019). The added transmission cost would be approximately $2.6 million. Land purchase replaces the

$65,000 per year cost of land lease at Site 1. The purchase price of ~98,500/acre[1] was based on two vacant industrial lots near Centralia, Washington.

5.4.1 Case 4: NuScale Facility at the Coal Plant Site in Centralia Washington

Two alternatives were developed for the Centralia site. The first alternative evaluated the LCOE for two NuScale plants to replace the current coal plants at the site, which would be of similar size to the current coal plant capacities. The second case evaluated adding only one NuScale plant at the site in one of the remediated brownfield coal mine sites, which would take advantage of the coal plant that will be removed because TransAlta may convert the remaining coal plant to natural gas and operate it until 2045.

According to the agreements with NuScale only the LCOE will be published. The NuScale costs at the Centralia site are lower than the $55.00/MWh provided by UAMPS for a NuScale reactor deployed at the INL site at approximately $53.88/MWh with two plants and $53.98/MWh with one plant (see **Table 5.20**). These values are the comparative baseline values in every table in this section against which other cases are compared.

Though the cost savings are not included in this analysis because they are beyond the scope, NuScale believes there are a number of advantages to the two-plant combination that could reduce the costs:

- Sharing systems (radioactive waste processing, site cooling water, chilled water, demineralized water, pool surge control, nitrogen, auxiliary boiler, and utility water) would minimize the quantity of components like tanks, pumps, valves, etc.
- Cooling tower quantities could be replaced or reduced with a site reservoir for condenser cooling.
- Modular construction would reduce the need for local skilled labor, reduce cost, and reduce schedule time. Fluor has positive experience with constructing modules (i.e., systems) in Fluor facilities and transporting them to sites when they are ready for installation. Doing do also allows construction activities to continue regardless of site climate constraints.
- The alternate AC power source (AAPS) can be shared among the four NuScale plants, thereby eliminating the need to have separate AAPS sources for each of the NuScale plants. The AAPS source is used to help start an individual nuclear power module (NPM) (e.g., restart an individual NPM in the event that all power has been lost).
- The security area could be optimized by evaluating the potential for creating one large protected area that encompasses all of the plant facilities. In addition, having one central alarm station and secondary alarm station for the site as opposed to separate stations could prove advantageous in terms of facility size and security staff requirements.
- Staffing levels could be optimized between plants. To satisfy NRC requirements, approximately 300 plant personnel (including security personnel) are needed to operate and maintain one NuScale plant (12 modules). There is an opportunity to optimize plant staffing levels if a multi-site services strategy provided by NuScale Plant Services is employed.
- Other optimizations also could be realized:
  - Optimize the building footprint.
  - Evaluate optimal turbine arrangement and subsequent turbine building(s) for a multi-plant site.

[1] LoopNet. Accessed July 1, 2020 at https://www.loopnet.com/search/commercial-real-estate/centralia-wa/for-sale/?sk=625515db6dbc22db9997f822824dcc1a&bb=59j64p1-vQh7o8sgf

– Assess the ability to use a central radioactive waste building(s) for central site processing, instead of having one radioactive waste building for each plant.
– Assess the ability to consolidate utility buildings, annex buildings, administration and training facilities, and warehouse buildings.
– Optimize the site for a combined dry cask storage location.
– Evaluate the feasibility of combining four control buildings into a single one while maintaining four separate control rooms.
– Localize fabrication for both the NPM and balance of plant equipment.
– Combine and optimize plant programs such as in-service testing, in-service inspection, maintenance, Reactor Pressure Vessel (RPV) surveillance, etc. Conduct optimization such as reducing the average quantity of inspection and test activities based on increased in-service component data.

As a part of the analysis and consistent with calculations for Site 1 in the previous section, the different levels of the WACC including evaluated costs at 3, 4, 5, 6 and 7 percent were evaluated. The 3 and 5 percent WACC levels provide a bounding level of organizations such as ENW. The 7 percent real rate reflects the LCOE at an IOU's real rate. Note that the interest rate of 1 percent adds more than $5/MWh and that the effect of compounding adds approximately $7/MWh when evaluating costs at 6 percent and 7 percent.

The effects of a lower fuel cost using an MIT value of $6.00/kgU for conversion rather than the $11.20/kgU that ENW was forecasting for 2028 were also evaluated. The prices for uranium and enrichment to the ENW 2024 prices of $35.5/lb of U_3O_8 and $74/SWU were also lowered. The change in fuel cost decreased the LCOE by $0.58/MWh from the $53.98 level, which we are considering the expected price. This further emphasizes how little fuel costs influence the overall LCOE. There is only about a $0.10/MWh difference in the cost between the one-plant and two-plant scenarios; the two-plant scenario is slightly less expensive because it takes advantage of a lower insurance cost and does not require an investment of $2.6 million in transmission lines.

Table 5.20. NuScale's LCOEs for different real interest rates for the WACC at the Centralia site ($/MWh).

		Interest Rate				
	LCOE	**3% WACC**	**4% WACC**	**5% WACC**	**6% WACC**	**7% WACC**
Replace 2 coal plants	$/MWh (2019$)	48.47	53.88	59.96	66.72	74.13
Replace 1 coal plant	$/MWh (2019$)	48.57	53.98	60.07	66.83	74.26

The project length impacts the LCOE through the added costs of interest during construction. The added interest costs approximately $2/MWh because the project length balloons by 3 years. Although only the project length was increased, typically the construction costs increase as annual fixed overhead accumulates (see **Table 5.21**).

Table 5.21. Project length at the Centralia site ($/MWh).

		Project Length					
	LCOE	**4 years**	**5 years**	**6 years**	**7 years**	**8 years**	**9 years**
Replace 2 coal plants	$/MWh (2019$)	52.57	53.22	53.88	54.55	55.24	55.95
Replace 1 coal plant	$/MWh (2019$)	52.67	53.32	53.98	54.66	55.35	56.06

Table 5.22 illustrates the impact on LCOE of extending the operating length from 40 years to 100 years with financing for the entire operating period. Although costs decline to $47/MWh from about $54/MWh, most plants will be financed for 40 years or less. The values indicated for 100 years provide the average cost across operating period. Once the plant is financed the 40 years cash costs will decline dramatically.

Table 5.22. Operational period length at the Centralia Site ($/MWh).

		Length of Operations			
	LCOE	**40 years**	**60 years**	**80 years**	**100 years**
Replace 2 coal plants	$/MWh (2019$)	53.88	49.21	47.45	46.71
Replace 1 coal plant	$/MWh (2019$)	53.98	49.31	47.55	46.80

Operating efficiency is a key factor in determining the busbar cost of energy. **Table 5.23Table 5.18** provides the cost per megawatt-hour as the operational efficiency changes from 28 percent to 32 percent. The operational efficiency will also decline because the turbine bypass is used to allow load following. The LCOE declines from $55/MWh (28 percent) to $53/MWh (32 percent).

Table 5.23. Impact of improving operating efficiency.

		Operating Efficiency				
	LCOE	**28% Efficient**	**29% Efficient**	**30% Efficient**	**31% Efficient**	**32% Efficient**
Replace 2 coal plants	$/MWh (2019$)	55.34	54.58	53.88	53.21	52.59
Replace 1 coal plant	$/MWh (2019$)	55.45	54.69	53.98	53.31	52.69

The capacity factor is shown from 85 to 95 percent (**Table 5.24**)**Table 5.24.** Impact of different capacity factors ($/MWh). At the 85 percent level the cost is approximately $5/MWh more than the baseline value. Capacity factor evaluations may be important if the facility is to enter the regulation markets where capacity may be purchased but not used. The result also indicates that a decrease to 90 percent would have approximately a $2.8/MWh increase in the LCOE.

Table 5.24. Impact of different capacity factors ($/MWh).

		Capacity Factor		
	LCOE	**85%**	**90%**	**95%**
Replace 2 coal plants	$/MWh (2019$)	59.66	56.61	53.88
Replace 1 coal plant	$/MWh (2019$)	59.77	56.72	53.98

NuScale would have the same opportunities for added revenues from flexible ramping and ancillary services as discussed in Case 2.

5.4.1.1 Conclusions about the Centralia Site for NuScale

With the value of electricity on the Mid-Columbia Exchange averaging approximately $23/MWh and expected to rise to $35/MWh (see Section 5.4.1), and if this is the market price to compete with prior to 2030, the NuScale plant would require about a $19/MWh subsidy for ENW to break even in the expected case ($53.88/MWh with two plants and $53.98/MWh with one plant). If nuclear is the only non-emitting dispatchable resource, the penalty for carbon emitting resources ($60/MWh) makes the SMR cost competitive with NGCC generating at $36.61/MWh, which, including the penalty, would cost $96.61/MWh.

Perhaps with the EIM expanding to include most of the state of Washington, there will be a wholesale market by the time the NuScale plant is built. If the CAISO wholesale market is expanded to the region, the value of ancillary services could be met by the NuScale plant. Regulation Up prices varied between $2.88/MWh to $6.86/MWh while Regulation Down prices ranged from $3.03/MWh to $5.29/MWh. The prices for these services appeared to decline over the collection period from 2009 to 2014 (Zhou 2016). These prices are above the cost of the energy. Thus, the NuScale plant could earn as much as $35/MWh for energy and add on the ancillary services value if a wholesale market opened in the future for this product, if this is the market price to compete with prior to 2030.

Thus, given the CETA charges for NGCC generation of $60/MWh, a NuScale plant at the Centralia site should be a competitive resource after 2029. However, Site 1 provides about a $3/MWh advantage over the Centralia site due to the value of the savings for the remaining WNP-1 plant at Site 1, which was never completed.

5.4.2 Case 5: GEH BWRX-300s at the Coal Plant Site in Centralia Washington

Two alternatives were developed for the Centralia site. The first alternative evaluated the LCOE for four GEH BWRX-300s to replace the current two coal plants at the site, which would be of similar size. The second case evaluated adding only two GEH BWRX-300s at the site in one of the remediated brownfield coal mine sites, which would take advantage of the coal plant that will be removed because TransAlta may convert the remaining coal plant to natural gas and operate it until 2045 when carbon emitting resources such as coal and natural gas plants will be disallowed.

According to the agreements with GEH only the LCOE will be published. The GEH BWRX-300 LCOEs of $50.52/MWh (replace two coal plants) and $50.70/MWh (replace one coal plant) at the Centralia site are higher than the $43.98/MWh at Site 1 (see **Table 5.25**) because of an added year of construction and the lack of savings for facilities already in place at Site 1.

As a part of the analysis, and consistent with calculations for Site 1 in the previous sections, we evaluated the different levels of the WACC at 3, 4, 5, 6, and 7 percent. The 3 and 5 percent WACC levels provide a bounding level for organizations such as ENW. The 7 percent real rate reflects the LCOE at an IOU's real rate. Note that the interest rate of 1 percent adds approximately \$4.50/MWh at lower values of the WACC and that the effect of compounding adds almost \$6.00/MWh to costs when evaluated at 6 percent and 7 percent.

We also evaluated the effects of a lower fuel cost using an MIT value of \$6.00/kgU for conversion rather than the \$11.20/kgU that ENW was forecasting for 2028. We also lowered the prices for uranium and enrichment to the ENW 2024 prices of \$35.5/lb of U_3O_8 and \$74/SWU. The change in fuel cost decreased the LCOE by \$0.59/MWh from the reference value at 4 percent. This further emphasizes how little fuel costs influence the overall LCOE.

Table 5.25. GEH BWRX-300's LCOEs for different real interest rates for the WACC at the Centralia site (\$/MWh).

	Interest Rate					
	LCOE	**3% WACC**	**4% WACC**	**5% WACC**	**6% WACC**	**7% WACC**
Replace 2 coal plants	\$/MWh (2019\$)	46.05	50.52	55.37	60.88	66.74
Replace 1 coal plant	\$/MWh (2019\$)	46.23	50.70	55.65	61.06	66.92

The project length impacts the LCOE through the added costs of interest during construction. The added interest costs increase the LCOE by more than \$2/MWh because the project length balloons by 4 years. Although only the project length was increased, typically the construction costs increase as annual fixed overheads accumulate (see **Table 5.26**).

Table 5.26. Project length at the Centralia site (\$/MWh).

	Project Length						
	LCOE	**4 years**	**5 years**	**6 years**	**7 years**	**8 years**	**9 years**
Replace 2 coal plants	\$/MWh (2019\$)	49.98	50.52	51.07	51.53	52.21	52.80
Replace 1 coal plant	\$/MWh (2019\$)	50.16	50.70	51.25	51.81	52.39	52.98

Table 5.27 provides the impact on LCOE of extending the operating length from 40 years to 100 years. Although costs decline to \$43/MWh from just more than \$50.5/MWh, most plants will be financed for 40 years or less. The value for 100 years provides the average cost across the operating period. Once the plant is financed the 40 years cash costs will decline dramatically.

Table 5.27. Operational period length at the Centralia Site (\$/MWh).

	Length of Operations				
	LCOE	**40 years**	**60 years**	**80 years**	**100 years**
Replace 2 coal plants	\$/MWh (2019\$)	50.52	45.88	48.67	42.99

Replace 1 coal plant	$/MWh (2019$)	50.70	46.06	44.16	43.27

Operating efficiency is a key factor in determining the busbar cost of energy. **Table 5.28** provides costs per megawatt-hour as the operational efficiency changes from 28 percent to 32 percent. The 32 percent reflects the actual efficiency claimed by GEH for their plant. The operational efficiency will also decline because the turbine bypass is used to allow load following. The LCOE declines from $54.5/MWh (28 percent) to $50.5/MWh (32 percent).

Table 5.28. Impact of improving operating efficiency.

		Operating Efficiency				
	LCOE	**28% Efficient**	**29% Efficient**	**30% Efficient**	**31% Efficient**	**32% Efficient**
Replace 2 coal plants	$/MWh (2019$)	54.52	53.58	52.59	51.87	50.52
Replace 1 coal plant	$/MWh (2019$)	54.73	53.78	52.89	52.06	50.70

The capacity factor was evaluated from 85 to 95 percent (**Table 5.29**). At the 85 percent level, the cost is almost $5.5/MWh more than at 95 percent for both alternatives. Capacity factor evaluations may be important if the facility is to enter the load-following markets where steam is exhausted rather than used for generation. The result also indicates that a decrease to 90 percent would increase the LCOE approximately $2.6/MWh for both alternatives.

Table 5.29. Impact of lower capacity factors.

		Capacity Factor		
	LCOE	**85%**	**90%**	**95%**
Replace 2 coal plants	$/MWh (2019$)	55.93	53.07	50.42
Replace 1 coal plant	$/MWh (2019$)	56.13	53.26	50.70

The BWRX-300 would have the same opportunities for added revenue from ancillary services as those discussed for Case 3.

5.4.2.1 Conclusions at the Centralia Site for the BWRX-300 Alternatives

With the value of electricity on the Mid-Columbia Exchange averaging approximately $23/MWh, and expected to rise to $35/MWh (see Section 5.4.1), and if this is the market price to compete with prior to 2030, the GEH BWRX-300 would require about a $15.4/MWh to $15.7/MWh subsidy for ENW to break even in the expected case ($50.522/MWh with two plants and $50.70/MWh with one plant). If nuclear power is the only non-emitting dispatchable resource, the penalty for carbon emitting resources (60/MWh) make it cost competitive with NGCC at $36.61/MWh, which, including the penalty, would cost $96.61/MWh.

Perhaps with the EIM expanding to include most of the state of Washington there will be a wholesale market by the time the GEH BWRX-300 is built. The locational market prices are above the cost of the energy today. Thus, the GEH BWRX-300 could earn as much as $35/MWh for energy. Thus, given the CETA charges for NGCC generation of $60/MWh, a GEH BWRX-300 at the Centralia site should be a competitive resource if NGCC generation is the only resource competing after 2029. Unless significant cost savings can be shown for multiple plants together, reducing the overall costs by more than $5.5/MWh, Site 1 even with transmission charges is a lower cost alternative to the Centralia site.

6.0 Firm and Near-firm Carbon-Free Generation Competition

Firm and near-firm renewable energy grid generation resources may provide competition to SMR generation. For example, a Minnesota utility, Great River Energy, is installing a 1 MW, 150 MWh storage system developed by Form Energy (Spector 2020). This is a FOAK facility, but it will provide Great River Energy with dispatchable wind power. Given the relative short timeline from permitting to generation for most of these resources and their relatively inexpensive power, they may provide stiff competition to the longer permitting to generation time paths for SMRs. However, renewable energy suffers from its variability and, although it is of low cost compared to firm power alternatives, it fails to provide the flexibility required to meet long duration periods when wind and sun are not providing adequate electricity. The question then becomes whether renewables can be firmed up at low enough costs to be competitive in the flexible market. An MIT study indicates that storage costs need to be perhaps as low as $20/kWh for long-term storage to be feasible. But that value ends up being a worst-case scenario (Roberts 2020).

6.1 Long-term Storage

Currently, the cost for long-term storage is prohibitively high to keep the lights on using only variable renewable energy. Lithium ion batteries cost approximately $200/kWh for approximately 4 hours of storage (Hanley 2020). The storage is valuable though because it has high ramping speeds and is dispatchable. However, storage cannot currently cover 100 percent of outage times that could occur with variable energy resources like wind and solar. NREL forecasts costs potentially dropping to $76/kWh at the low end and $258/kWh at the high end by 2050 (Cole and Frazier 2019). The high-end value has already been surpassed in 2020 according to Hanley (2020). The low-end value still does not reach the $20/kWh required in the MIT study. However, the MIT study indicates other ways to reach firm dispatchable power without going to $20/kWh by using transmission, demand-side management, and supplemental generation. The price of batteries only needs to drop to $700/kW and $150/kWh if wind and solar reach 95 percent of needs. The study set the capital cost of wind at $1,500/kW. The study also assumed no further price decreases in wind or solar (Zigler et al. 2019). Some forecasts for wind LCOEs indicate they will drop a further 26 percent by 2025 (Shouman 2020). That is probably enough to cover the cost of long-term storage such as Form Energy’s. In all likelihood, some combination of long duration batteries and fast ramping batteries will be required to stabilize the grid if they are competitive.

6.2 Wind and Solar with Long-Term Storage

The combined cost of the long-term storage solution plus wind is dependent on the quality of the wind and the turbine size. Washington and Oregon are home to several wind farms. According to the NREL wind map, the Pacific Northwest wind averages in the 5.5–6.5 miles per second range in the areas where wind farms exist. Capacity factors for that wind speed in the PPAs indicate the cost of wind is in the range of $40–$55/MWh for recent PPAs in the West (LBL 2018). Depending on the vintage of the wind farm production, tax credits need to be added back to understand the cost of power. An LCOE for wind in the Columbia Basin was calculated assuming $1,470/kW (2018$), $29/kW O&M costs, at discount rates—5 percent and 8 percent, and two capacity factors, 35 percent and 40 percent (see **Table 6.1**). A DOE report (Wiser et al. 2019) indicated that the cost of wind energy is averaging below $20/MWh. These wind projects are earning a production tax credit of $24/MWh (Davis 2019). These prices are not for firm wind. A long duration battery as noted previously would be required.

Note that ENW’s wind farm at the Nine Canyon Wind Project costs between $59/MWh and $83/MWh depending on the wind capacity in a year (ENW 2018). Thus, currently installed wind is more expensive than the projected SMR costs and a SMR could provide dispatchable power.

Table 6.1. LCOE for wind in the Columbia Basin before tax credits.

	Discount Rate	
Capacity Factor	5%	8%
35%	$44/MWh	$55/MWh
40%	$39/MWh	$49/MWh

Solar costs depend primarily on the installed capital cost of the solar farm and the locality insolation. An IHS Markit forecast estimated that solar power LCOEs would be a low as $58/MWh by 2028. The forecast LCOE was based on a $807/kW installed cost for fixed tilt. NREL's forecast (2019) for the future installed capital cost of solar for 2028 approximately matches that cost. They are forecasting approximately $600–$1000/kW by 2045. Those prices would translate to a $10/MWh–$20/MWh cost. This does not include the cost of firming solar power.

According to the MIT study a solar/wind mix is cost competitive with nuclear power for baseload electricity at about $75/MWh when energy storage reaches $10–20/kWh. To reach a competitive natural peaker plant price of $77/MWh, battery prices must fall to $5/kWh. The interesting point from the MIT article is that much higher battery prices can be associated with a stable grid at up to 95 percent of load. This contrasts with another MIT study that indicates that with battery prices at $150/kWh, they can only meet 4 percent to16 percent of peak power requirements (Mallapragada et al. 2020).

6.3 Future LCOEs

The EIA forecast for generation resources entering service in 2025 (EIA 2020b) indicates that advanced nuclear resources will not be available at that time, which is expected and indicates relatively low costs for NGCC, geothermal, onshore wind, solar photovoltaic, and hydroelectric, all within $10/MWh of each other. Note that the LCOEs include the cost of transmission as well (see **Table 6.2**). The weighted average is the regional weighted LCOE for the U.S. The EIA LCOE estimate for geothermal is $37/MWh and probably references easier-to-access fields in California, Nevada, and Utah with technology improvements for standard geothermal technologies. In

Table 6.3, note that advanced nuclear costs are forecast at approximately $82/MWh before the investment tax credit, substantially higher than our estimates for the SMRs in this study. Thus, geothermal, a dispatchable generation source, is available to meet firm resource requirements and has the capability to provide ancillary services (GEA 2013). The issue for geothermal is whether the resource will be available in Washington at competitive prices in the next 10 years. There appears to be significant geothermal resource above the 200ºC range, which is favorable for geothermal development (see Figure 6.1). Further investigation of the resource indicated there are two areas within Washington State that meet the two requirements for future geothermal electricity production; thermal potential and easy access to transmission or favorability (Source: https://www.eia.gov/energyexplained/geothermal/where-geothermal-energy-is-found.php#:~:text=U.S.%20geothermal%20power%20plants%20are,most%20electricity%20from%20geothermal%20energy.

Figure 6.2 and Figure 6.3). The portion of the figure labeled (a) indicates thermal potential while the portion labeled (b) indicates potential feasibility (proximity to transmission and lack of land use restrictions). Points 5 and 6 along the Columbia River are the Wind River area and the Roosevelt area. Both sites should have few issues with permitting and location to existing transmission systems (Boschmann et al. 2014). Additionally, the cost of extracting electricity needs to be competitive. A recent study of enhanced geothermal systems indicates the cost could be in the $47/MWh range including transmission costs (2019$) (Cladouhos 2018). Given the error band for the estimates the LCOEs could be equivalent. Should If the estimates prove accurate and based on SMR LCOEs, SMRs would need a $0/MWh–$30/MWh subsidy to be competitive with geothermal. Currently, there is only 2.6 GWe of geothermal, mainly in the WECC and Hawaii. Thus, geothermal and SMRs may compete for the approximate 5 GWe of capacity Washington State needs in firm capacity. However, a further question is whether in 10 years the battery market will make wind and solar a cost-competitive dispatchable resource relative to geothermal and SMRs.

Table 6.2. Forecast weighted[(a)] LCOEs for generation resources entering service in 2025 ($/MWh 2019$).

Plant Type	Capacity Factor (percent)	Levelized Capital Cost	Levelized Fixed O&M[(b)]	Levelized Variable O&M	Levelized Transmission Cost	Total System LCOE	Levelized Tax Credit[(c)]	Total LCOE Including Tax Credit
Ultra-supercritical coal	NB	NB	NB	NB	NB	NB	NB	NB
Combined cycle	87	7.48	1.59	26.4	1.13	36.61	NA	36.61
Combustion turbine	30	16.1	2.65	46.51	3.44	68.71	NA	68.71
Advanced **nuclear**	NB	NB	NB	NB	NB	NB	NB	NB
Geothermal	90	20.36	14.5	1.16	1.45	37.47	-2.04	35.44
Biomass	NB	NB	NB	NB	NB	NB	NB	NB
Wind, **onshore**	40	23.51	7.51	0	3.08	34.1	NA	34.1
Wind, offshore	45	84	27.89	0	3.15	115.04	NA	115.04
Solar **photovoltaic[(d)]**	30	24.12	5.77	0	2.91	32.8	-2.41	30.39

Hydroelectric[e, f]	73	28.89	7.64	1.39	1.62	39.54	NA	39.54

(a) The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2023 to 2025. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as NB, or not built.

(b) O&M = operations and maintenance.

(c) The tax credit component is based on targeted federal tax credits such as the production tax credit (PTC) or investment tax credit (ITC) available for some technologies. It reflects tax credits available only for plants entering service in 2025 and the substantial phaseout of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as NA, or not available. The results are based on a regional model, and state or local incentives are not included in LCOE calculations. See text box on page 2 for details about how the tax credits are represented in the model (EIA 2020b).

(d) Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

(e) As modeled, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

(f) Costs are for the 2023 online year. Source: U.S. Energy Information Administration, Annual Energy Outlook 2020. See page 6 for details about the exception (EIA 2020b).

Table 6.3. Forecast unweighted LCOEs for generation resources entering service in 2025 ($/MWh 2019$).

Plant Type	Capacity Factor (percent)	Levelized Capital Cost	Levelized Fixed O&M[(a)]	Levelized Variable O&M	Levelized Transmission Cost	Total System LCOE	Levelized Tax Credit[(b)]	Total LCOE Including Tax Credit
Dispatchable technologies								
Ultra-supercritical coal	85	47.57	5.43	22.27	1.17	76.44	NA	76.44
Combined cycle	87	8.4	1.59	26.88	1.2	38.07	NA	38.07
Combustion turbine	30	16.17	2.65	44.33	3.47	66.62	NA	66.62
Advanced nuclear	90	56.12	15.36	9.06	1.1	81.65	-6.76	74.88
Geothermal	90	20.38	14.48	1.16	1.45	37.47	-2.04	35.43
Biomass	83	39.92	17.22	36.44	1.25	94.83	NA	94.83
Non-dispatchable technologies								
Wind, onshore	40	29.63	7.52	0	2.8	39.95	NA	39.95
Wind, offshore	44	90.95	28.65	0	2.65	122.25	NA	122.25
Solar photovoltaic[(c)]	29	26.14	6	0	3.59	35.74	-2.61	33.12
Hydroelectric[(e, d)]	59	37.28	10.57	3.07	1.87	52.79	NA	52.79

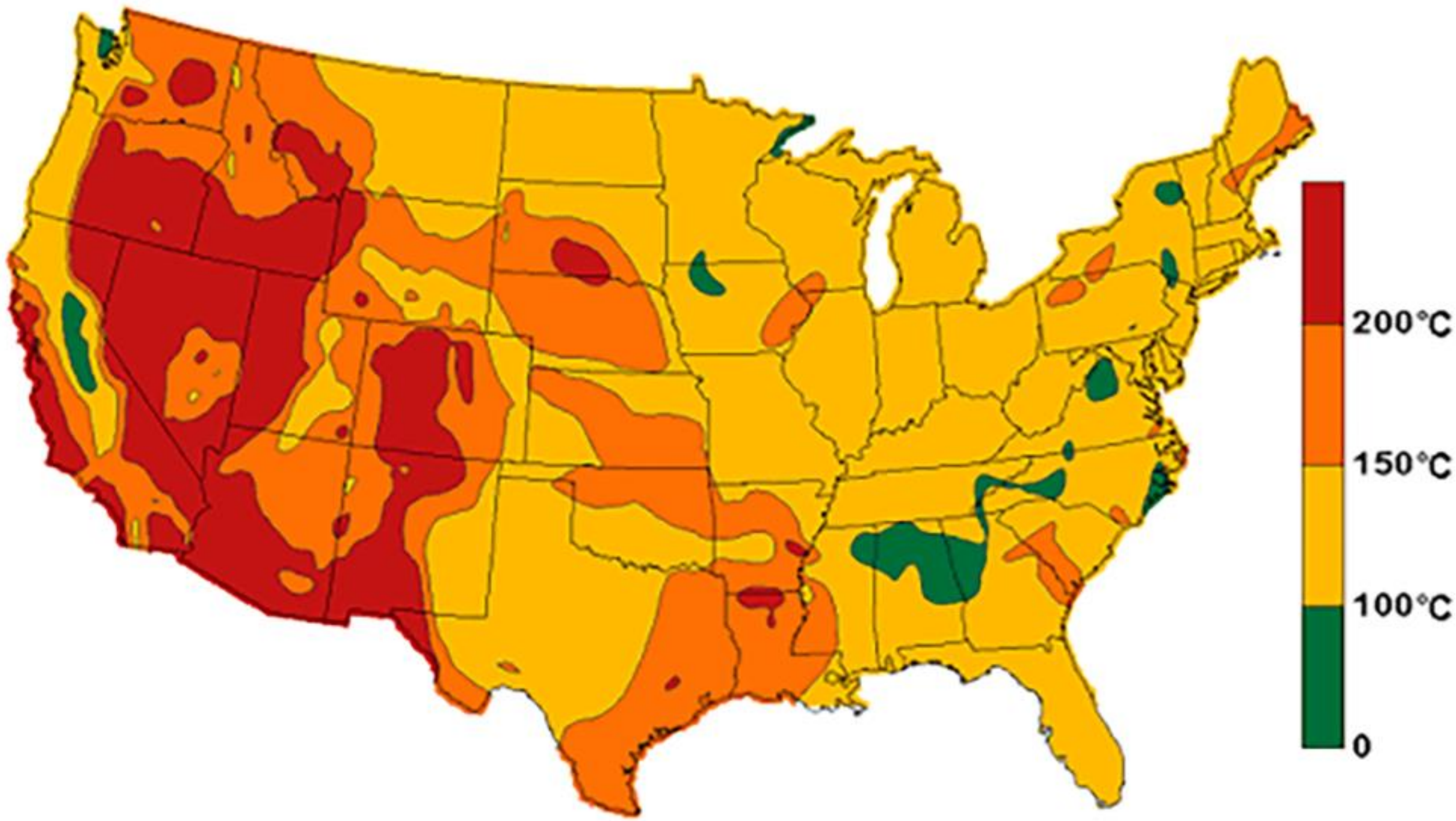
(a) O&M = operations and maintenance.

(b) The tax credit component is based on targeted federal tax credits such as the production tax credit (PTC) or investment tax credit (ITC) available for some technologies. It reflects tax credits available only for plants entering service in 2025 and the substantial phaseout of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as NA, or not available. The results are based on a regional model, and state or local incentives are not included in LCOE calculations.

(c) Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

(d) As modeled, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

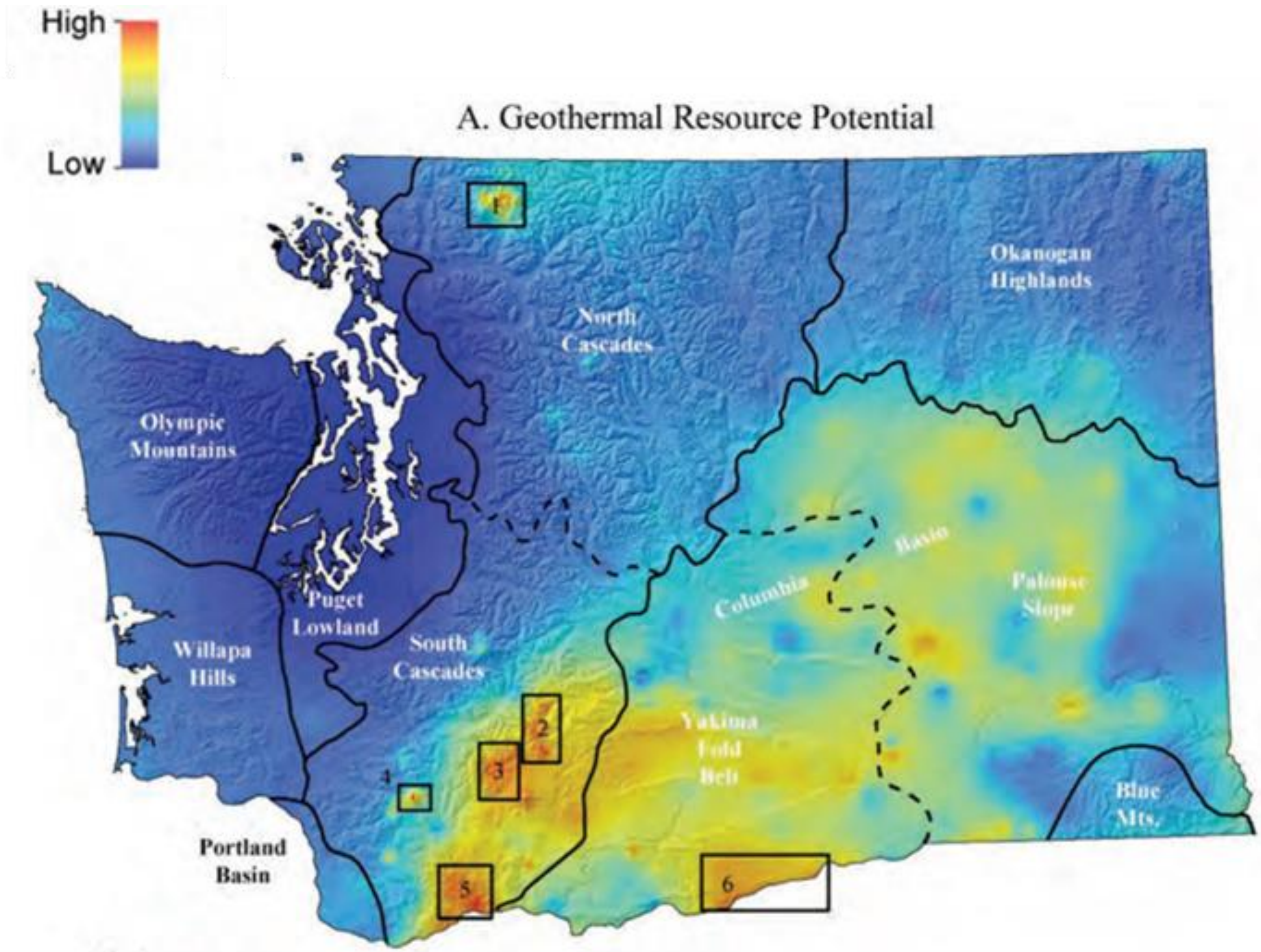
(e) Costs are for 2023 online year. Source: U.S. Energy Information Administration, Annual Energy Outlook 2020. See page 6 for details about the exception (EIA 2020b).



Source: U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy (public domain)

Source: https://www.eia.gov/energyexplained/geothermal/where-geothermal-energy-is-found.php#:~:text=U.S.%20geothermal%20power%20plants%20are,most%20electricity%20from%20geothermal%20energy.

Figure 6.1. Geothermal resources of the United States.



Source: https://www.eia.gov/energyexplained/geothermal/where-geothermal-energy-is-found.php#:~:text=U.S.%20geothermal%20power%20plants%20are,most%20electricity%20from%20geothermal%20energy.

Figure 6.2. Geothermal resource potential in Washington State.

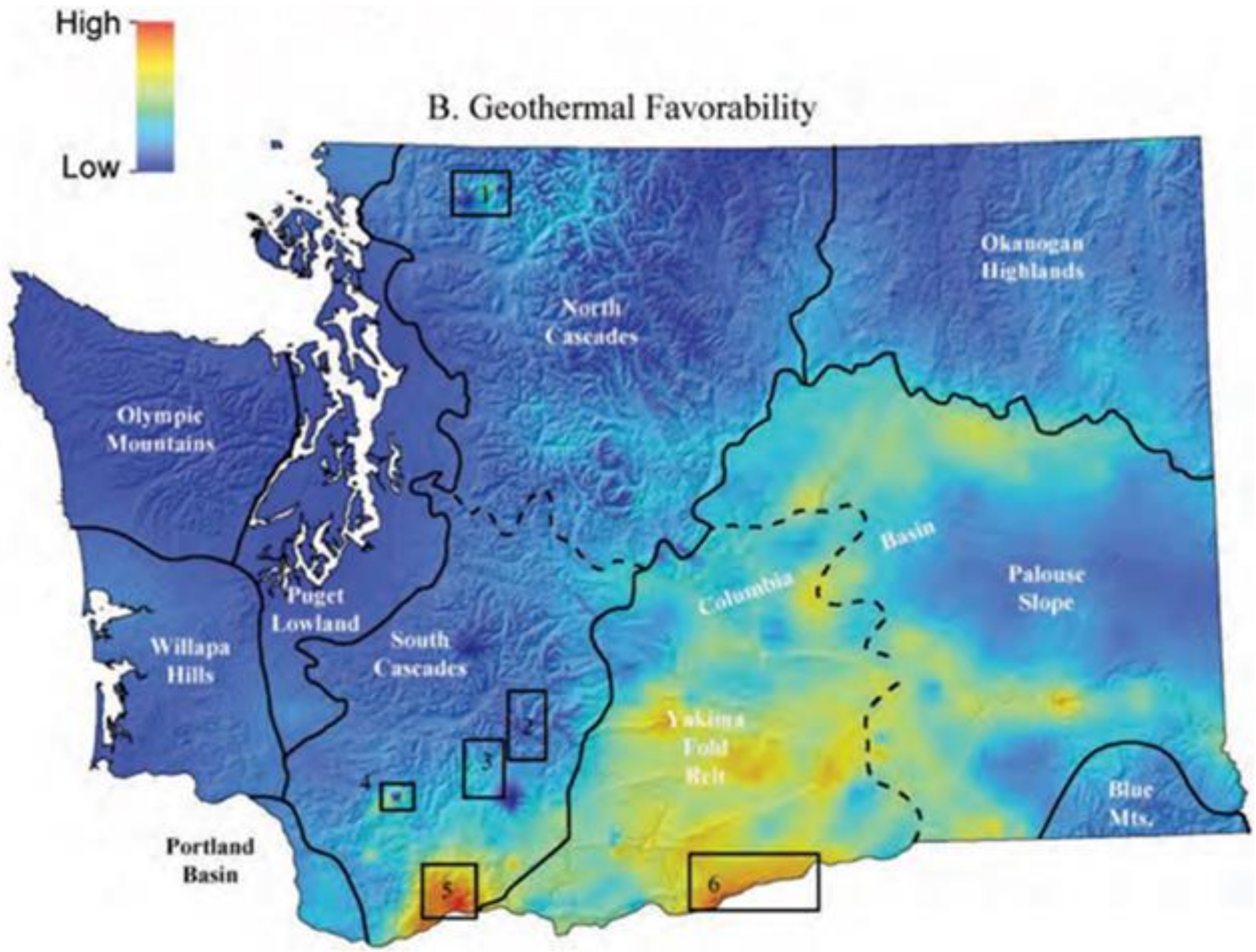


Figure 6.3. Geothermal resource favorability (accessibility to transmission) in Washington State.

7.0 Analysis of Results for NuScale and GEH BWRX-300

The following sections provide a summary of the results for the NuScale and GEH BWRX SMRs on a case-by-case basis. The LCOEs for the NuScale and GEH BWRX-300 SMRS are not directly comparable because of the different approaches taken to provide the estimated costs and associated LCOEs.

7.1 Comparison of NuScale Results

The UAMPS SMR at INL has a total project cost of approximately $6 billion. DOE has agreed to inject $1.35 billion into the project, reducing the overall target cost to $55.00/MWh (2018$) (UAMPS 2020a, 2020b). The DOE subsidy amounts to an approximate $15–$30/MWh subsidy to UAMPS' subscribers depending on the WACC and other assumptions used. The estimated project costs are based on a Class IV estimate. A Class III estimate will be provided in 2021, a Class II estimate at the end of 2022, and a Class I estimate in September 2024 (Burns &McDonnell 2020). The first unit is expected to be commercially operable in 2029 (Burns & McDonnell 2020) and the remaining facilities to be completed by August 2030. The resulting estimated LCOEs for Site 1 ($51/MWh) and the Centralia site ($54/MWh) would appear to be approximately correct for an NOAK facility given the project costs, target price, and subsidy levels. Given that there was very little difference in the LMPs for the two sites and transmission costs did not differ much, Site 1 would be the lower cost location for a NuScale SMR compared to Centralia. Site 1 provides about $300 million in savings due to operable infrastructure at the that can be used for the SMR in terms of pre-construction, construction, and construction time savings. Additionally, Site 1 is a place where the population accepts nuclear power and has a workforce in place, but additional workforce will be required to staff the SMR. But firm capacity will be needed in the future.

The main competitors with NuScale's SMR are NGCC, geothermal, and near-firm wind and solar. Electricity generated from NGCC resources costs utilities an additional $60/MWh, raising the cost to Washington utilities to $97/MWh. The LCOEs of geothermal, $37/MWh to $47/MWh, are below the NuScale LCOEs of $51/MWh, a $4/MWh to $14/MWh difference. Note that given the error band around the estimate for enhanced geothermal systems, the two estimates are probably equivalent. Including the geothermal tax credit adds $2.04/MWh to the difference increases the margin between NuScale and geothermal to $6/MWh to $16/MWh. If ENW structures the deal to sell the tax credits, the differential would decrease to $-1/MWh to $9/MWh. The real question is how much geothermal penetration will there be at this price? The heat maps indicated there were plenty of resources in the WECC to provide geothermal generation. However, there is only about 1.4 GW of capacity currently. Apparently, the lower variable costs of wind and solar do not allow new geothermal resources to enter the market. But firm capacity will be needed in the future.

NuScale's plant may receive premiums above the average market price. Because firm resources can produce power to meet the demand, they can receive the on-peak price and off-peak prices. On the other hand, wind only receives revenue when the wind blows. The premium for the Mid-Columbia Exchange appears to provide $3.7/MWh above the average price. In addition, because the SMR appears to meet the requirements of the EIM for Regulation Up and Reg Down product, NuScale may be able to receive premiums for providing that service to the EIM.

Range analysis was undertaken to understand the impact on LCOEs of changes in interest rates, project schedule, plant efficiency, operation period, and capacity factors. Increasing the interest rate by 2 percentage points increased the cost by $11/MWh above the $51/MWh cost for Site 1. Lengthening the project period by 3 years increased the LCOE to $2/MWh. The small change really does not show the complete impact of lengthening the project period because annual fixed costs would continue to accumulate and increase the cost. Increasing the operating period from 40 to 60 years decreased the

LCOE by $4/MWh. Reducing operating efficiency to 28 percent from 30 percent increased the costs by $1/MWh. Reducing the capacity factor to 85 percent raised the LCOE by $5/MWh for Site 1. Interest costs and capacity appear to be the largest cost factors for Site 1. An increased project period may actually be the worst problem because of the unavoidable fixed costs over the extended period (which were not assessed).

7.2 Comparison of GEH BWRX-300 Results

No FOAK estimates were found for the GEH BWRX-300. Thus, no comparison of the FOAK and the NOAK could be undertaken. In addition, remember that the GEH BWRX-300 and NuScale LCOEs are not intended to be directly compared in this study. GEH used a design-to-cost methodology with target pricing that is being confirmed as the design matures. NuScale’s estimate is based on the current design.

The main competitors of GEH BWRX-300 are NGCC, geothermal generation, and potentially near-firm wind and solar. Electricity generated by NGCC costs utilities an additional $60/MWh, raising the cost to Washington utilities to 96.61 starting in 2030. The LCOE of geothermal, $37/MWh to $47/MWh, is around the GEH BWRX-300 LCOE of $44/MWh, a $-3/MWh to $7/MWh difference. Note that given the error band around the estimate for enhanced geothermal systems, the two estimates are probably equivalent. Adding the geothermal tax credit adds $2/MWh to the range makes the difference $-1/MWh to $9/MWh. If ENW is able to structure the deal to sell the tax credits, the differential would decrease to $-7/MWh to $3/MWh. The real question is how much geothermal penetration will there be at the indicated prices? The heat maps indicated there were plenty of resources in the WECC to provide geothermal generation. However, there is only about 1.4 GW of capacity currently. Apparently, the lower marginal costs of wind and solar do not provide for an adequate return to new resources. But firm capacity will be needed in the future.

Given the lower costs of Site 1 ($44/MWh) compared to the Centralia site ($51/MWh), and the lack of a significant differential in transmission costs and locational market prices between the two sites, Site 1 will be the lower cost location to build the SMR compared to the Centralia Site. Site 1 already has infrastructure associated with WNP-1 that is deemed useful and that will reduce the costs by about $300 million in project costs in terms of pre-construction, construction, and construction time savings. Additionally, Site 1 is a place where the population accepts nuclear power and has a workforce in place, but additional workforce will be required to staff the SMR.

The GEH BWRX-300 plant may receive premiums above the average market price. Because firm resources can produce to meet demand, they can receive on-peak prices and off-peak prices, whereas wind only receives revenue when the wind blows. The premium for the Mid-Columbia Exchange appears to provide $4/MWh above the average price. In addition, because the SMR appears to meet the requirements of the EIM for Regulation Up and Regulation Down product, GEH may be able to receive premiums for providing that service to the EIM.

Range analysis was undertaken to understand the impact on LCOEs of changes in interest rates, project schedule, plant efficiency, operation period, and capacity factors. Increasing the interest rate by 2 percentage points increased the cost by $8/MWh above the $44/MWh cost for Site 1. Lengthening the project period by 3 years increased the LCOE by $1/MWh. The small change really does not show the complete impact of lengthening the project period because annual fixed costs would continue to accumulate and increase the cost. Increasing the operating period from 40 to 60 years decreased the LCOE by $1/MWh. Reducing operating efficiency to 30 percent from 32.8 percent increased the costs by $3/MWh. Reducing the capacity factor to 85 percent raised the LCOE by $5/MWh for Site 1. Interest costs and capacity appear to be the largest cost factors for Site 1. An increased project period may actually be the worst problem because of the unavoidable fixed costs over the extended period (which were not assessed).

8.0 Conclusions

Both NuScale ($51/MWh–$54/MWh) and GEH ($44–$51/MWh) LCOEs for an NOAK plant are above the future cost of geothermal, the only other potential non-carbon-emitting firm generation resource. Note that given the error band around the estimate for enhanced geothermal systems, the two estimates are probably equivalent. Note that the NuScale and GEH LCOEs cannot be directly compared because of the different methods used to estimate their costs. Whether there needs to be a subsidy for the NOAK plant to enter the market depends on the price and quantity of competing resources, the size of the future market, and the quantity of non-emitting resources that needs to be replaced and whether the UAMPs subscription price indicates that municipal utilities are willing to purchase electricity at $55/MWh. In addition, the quantity of non-emitting capacity depends on how many emitting resources Washington utilities must replace, the availability of unbundled RECs, and the quantity of energy conservation projects that have a positive net present value. Utilities can substitute up to 20 percent of the total sales with unbundled RECs and energy conservation projects.

EIA estimates geothermal entering the market in 2025 at $37/MWh (2019$) and this estimate is probably reflective of easier-to-access fields in California, Nevada, and Utah. Another study estimated the enhanced geothermal system would cost around $47/MWh (2019$), enter service in about 10 years, and the cost reflects the probable LCOE for geothermal in Washington State. Entities that have a tax appetite get a $2/MWh tax credit that reduces the cost to $35/MWh to $45/MWh. NGCC could be purchased between 2030 and 2045 at a penalty price of $97/MWh. These two resources bound the market for firm resources. If NGCC is required, no subsidy would be required because NGCC would set the market price. However, near-firm renewable resources could provide a portion of the energy required by the time the first SMR reaches commercial operation. Variable renewable resources with batteries or other storage could provide approximately 4 percent of the firm power requirements at current prices. According to two separate MIT studies, wind plus battery could provide between 16 and 95 percent of firm power requirements in the future at battery prices of about $150/kWh. With the entrance of BPA into the EIM, power could flow inexpensively from other EIM areas with an abundance of solar and wind and significantly reduced transmission costs. Only one transmission cost is applied rather than pancaking the transmission costs without the EIM. One issue that will need to be understood is how the state of Washington will handle the mix of electricity coming over the wires, which will include carbon-emitting resources. The benefits of the EIM could be exemplified by UAMPS shipping power to Washington State. The EIM reduces the overall transmission costs from $24/MWh to $4/MWh.

The estimated Washington firm market capacity due to replacing carbon-emitting resources is about 5 GWe. With a growing population and increasing EV penetration, the capacity requirement could be larger. Near-firm production provides a small range for geothermal and SMRs to fill as the near-firm generation is needed to replace approximately 5 GWe of natural gas and coal generating capacity for Washington State.

In a Day-Ahead Market like CAISO's, the marginal cost of delivering energy provides the supply curve for electricity delivery. As such, geothermal and SMRs would enter up to the quantity meeting their marginal costs. Everyone would receive the highest bid price. The price obviously does not cover long-run costs, but the expectation is that power shortages over time will provide prices high enough to cover the costs. In this scenario, no subsidy would be required.

Bilateral agreements, such as those occurring with UAMPS and subscribers to their plant, are another approach to determining if a subsidy is required. Subscribers will purchase the lowest-cost generation to meet their energy needs. If the UAMPs subscription target is an indicator, utilities appear willing to pay $55/MWh, which indicates that a subsidy of $15–$30/MWh is required for the FOAK plant depending on the assumptions used. This would also suggest that if the price of the NOAK plant is below the $55/MWh target, utilities would not need any further subsidy. If the price for SMR electricity is higher, then a subsidy would be required to bring the cost down to the point where utilities would buy the power. In addition, if the project can be properly structured, the cost of the production tax credit could be potentially sold, which would provide an approximate $7/MWh subsidy according to the EIA. This would indicate that if both GEH and NuScale can reach their estimates for an NOAK plant they would need no additional subsidy.

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Appendix A – Questionnaires

A.1 GEH and NuScale Questionnaire

Assume Nth-of-a-Kind Plant Deployment

Please provide ranges for applicable items with expected, low and high.

1.0 Plant Data	**Expected**	**Low**	**High**
Plant name -			
Gross of Plant Power (MWth/MWe)-	______	______	______
Net Plant Efficiency –	______	______	______
Rolling Plant Capacity Factor Over Several Years –	______	______	______
Fuel Form (UO2, metallic, aqueous, etc.) & Enrichment (LEU/HALEU/other) –	______	______	______
Ultimate Heat Sink (water or air cooling) -	______	______	______
Number of Individual Modules per Plant (if applicable) –			
Site Size (Acres)	______	______	______
Emergency Planning Zone-Plume exposure pathway (Miles)	______	______	______
Probability of attaining the mileage (Probability)	______	______	______
Emergency Planning Zone-Ingestion pathway (Miles)	______	______	______
Probability of attaining the mileage (Probability)	______	______	______
2.0 Economics Data			
Interest rate – site acquisition, licensing and civil works phase	______	______	______
Interest rate – construction phase	______	______	______
Interest rate – operating phase	______	______	______
Interest rate – decommissioning sinking fund	______	______	______
Interest rate – other sinking funds?	______	______	______
Ownership – discount rate	______	______	______
Time period – licensing, acquisition, and civil works phase	______	______	______
• Expected Cost	______	______	______
Time period – construction phase	______	______	______
• Construction costs and spend curve	______	______	______
• Cost to tie into the electric grid including new transmission lines	______	______	______
• Safety amount of concrete used to construct plant	______	______	______
• Non-safety amount of concrete used to construct plant	______	______	______
• Safety amount of steel used to construct plant	______	______	______
• Non-safety amount of steel used to construct plant	______	______	______
• Total Cost	______	______	______
Time period – start up months	______	______	______
Operating Phase – number of years	______	______	______
• Estimated annual maintenance costs	______	______	______
• Estimate of annual fuel costs (what are underlying assumptions for SWU, O3O8, etc. to help normalize across multiple vendors)	______	______	______
• Estimate of annual costs to store fuel at site	______	______	______
Number of Plant Personnel & Estimated Annual Salaries	______	______	______
• Engineering & Maintenance Support	______	______	______

• Average annual salaries	______	______	______
• Operations	______	______	______
• Average annual salaries	______	______	______
• Refueling Support	______	______	______
• Average annual salaries	______	______	______
• Security cost estimate	______	______	______
• Overhead Personnel	______	______	______
• Average annual salaries	______	______	______
Deactivation & Decommissioning Phase – Number of Years	______	______	______
• Estimated Cost	______	______	______

3.0 Additional Information for Consideration

Is there a phased deployment of a modular SMR, or multiple single SMR units at one site? If it is a phased deployment of modules, what is the time period to achieve first revenue and is this shorter than the entire plant construction phase?

Summarize Attributes for Flexible Operations (e.g., load following, frequency control, reactive power, etc.)

Summarize Approach to Flexible Operations: For example, dumping steam to condenser or reactor power maneuvering and response time to significant load changes (seasonal, weekly, daily, 5-minutes, etc.).

Summarize Non-baseload Applications: shifting power to energy storage, hydrogen production, pumped hydro, or providing process heat for industrial uses during periods of low grid demand. Include information on process heat temperature for these applications.

Electrical grid “cold start” capability?

Capable of micro grid / Island mode operations?

Fuel reload frequency and planned outage durations

What is additional cost per MWe to add new capacity to support new grid demand?

What is ratio of installed MWe vs regional daily peak grid demand?

What is ratio of installed MWe vs regional daily average grid demand?

A.2 Energy Northwest Questionnaire

Will the NuScale facility be a part of Energy Northwest?
If yes, what discount rate will be used to determine delivery of electricity at cost?
What is Energy Northwest’s overhead costs for adding the NuScale facility? Please break it down by type of overhead.

• Staff recruitment	$______
• Office overhead	$______
• Management Expense	$______
• Property taxes or payments in lieu of taxes (PILT)	$______
• Insurance	$______
• Cost of Borrowing	%______

- Salary Overheads %______
    - Taxes %______
    - Insurance %______
    - Benefits %______
    - Fringes %______
- Any other salary related costs ______
- Other (Please enumerate) ______

Will there be site cost/savings associated with using the Energy Northwest site? Enumerate added savings and added costs by line item?

- Land and Land Rights $______
- Site permitting $______
- Plant licensing $______
- Plant Permits $______
- Plant Studies $______
- Plant Reports $______
- Public Awareness Programs $______
- Site Remediation Work $______
- Additional Transmission Capacity Required $______
- Will there be additional costs for siting the SMR next to a traditional LWR? $______
- How much footprint is available for the SMR? $______

Pacific Northwest National Laboratory

902 Battelle Boulevard
P.O. Box 999
Richland, WA 99354
1-888-375-PNNL (7665)

www.pnnl.gov