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Comments of the Joint Commenters on the Columbia River System Operations Draft Environmental Impact Statement

NW Energy Coalition has prepared these comments on the Columbia River System Operations (CRSO) Draft Environmental Impact Statement (DEIS), which are supported by Idaho Conservation League, Natural Resources Defense Council, Sierra Club, American Rivers and Save Our wild Salmon Coalition, hereafter the "Joint Commenters."

NW Energy Coalition (NWEC) is an alliance of over 100 environmental, civic, and human service organizations, progressive utilities, and businesses in Oregon, Washington, Idaho, Montana and British Columbia. We promote development of renewable energy and energy conservation, consumer protection, low-income energy assistance, and fish and wildlife restoration on the Columbia and Snake rivers. Since 1981, NWEC has engaged in energy planning and policy in the Pacific Northwest, including directly engaging in the operations of the Columbia River System.

Idaho Conservation League (ICL) is Idaho's largest and oldest statewide conservation group. Since our inception in 1973, we have engaged in energy planning and resource development to protect the clear air, clean water, and vibrant fish and wildlife that make our state and region special. On behalf of our more than 25,000 supporters, we submit these comments on the necessary elements of a complete and rigorous evaluation of alternatives to the current Columbia River System Operations.

Natural Resources Defense Council's (NRDC) staff of approximately 700 scientists, lawyers, and policy experts work to safeguard the earth, its people, its plants and animals, and the natural systems on which all life depends. NRDC's energy work is focused on accelerating the shift from fossil fuels to a clean energy future transition, removing barriers to cost-effective energy efficiency, and helping impacted communities fight fossil-fuel extraction. NRDC has a long history of working on energy issues and planning in the Pacific Northwest. On behalf of our 3 million members and activists, we submit these comments to draw attention, improve agency decision-making, and inform the impacted public regarding the energy analysis of the CRSO DEIS.

Sierra Club is the nation's oldest and largest grassroots environmental organization. Founded in 1892, Sierra Club now has over three million members and supporters, including more than 250,000 in the Pacific Northwest. Sierra Club's mission is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives.

American Rivers, founded in 1973, is the leading conservation organization working to protect our nation's rivers and streams. American Rivers' mission is to protect wild rivers, restore damaged rivers and conserve clean water for people and nature. nature. Our strength lies in our 355,000 members, supporters and volunteers from all 50 states, thousands of whom live, work and recreate in the Columbia Basin.

Save Our wild Salmon Coalition (SOS) formed in 1992. SOS brings together conservationists, sport and commercial fishing interests, clean energy and orca advocates, scientists and others working to protect and restore abundant, self-sustaining populations of Columbia and Snake river salmon and steelhead and the many benefits they bring to Northwest communities and ecosystems.

Key Findings

The DEIS confirms that dam breaching and clean energy power replacement can maintain electric system reliability while providing the best chance for fish restoration.

- The DEIS acknowledges that a replacement portfolio of new, clean energy resources can meet electricity needs without compromising system reliability.
- The DEIS found that dam breaching is the only option that, with additional improvements, could increase fish return rates to a level that may support recovery and preservation of at least some salmon and steelhead populations.

The DEIS fails to meet energy industry resource planning standards, resulting in numerous inaccuracies and an exaggerated cost for clean energy power replacement.

- The errors stem from a failure to adequately consider a full range of possible replacement resources, a failure to optimize the selected replacement resources to achieve the most efficient outcome, and outdated and incomplete cost assumptions for replacement resources.
- These shortcomings were exacerbated by the use of inconsistent time frames for different elements of the analysis, the use of a static year rather than a multi-year analysis of the replacement portfolio, and by the arbitrary assumption of a 2022 implementation date.
- The result is an exaggerated estimate of clean energy replacement costs leading to a similarly exaggerated estimate of impacts to consumer electricity bills

Because the DEIS fails to provide the accurate information needed to make informed decisions, a new, more rigorous study is required.

- A study that meets the standards of the region's utilities and the Northwest Power and Conservation Council for integrated resource planning (IRP) would examine energy and capacity needs over a span of 20 years, fully explore demand requirements and resource options, and test and optimize combinations of possible replacement resources. The result would be:
  - Significantly lower costs to acquire wind, solar, storage, and demand-side resources.
  - Less need for new generating and transmission resources because demand response and energy efficiency would make larger contributions than the DEIS assumes.
  - A more efficient and cost-effective system that could improve region-wide reliability and greatly reduce the impact on customer rates.

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1. Introduction

In these comments, the Joint Commenters respond to elements contained in the CRSO DEIS concerning the feasibility and cost of replacing the electricity and grid services currently provided by hydropower generation at the four lower Snake River dams with a portfolio of new clean energy resources.

The Joint Commenters have reviewed the Preferred Alternative (PA) and the four Multiple Objective Alternatives, particularly Multiple Objective Alternative 3 (MO3) proposing breach of the four Lower Snake River (LSR) dams and retirement of their associated hydrogeneration facilities, along with additional spill operations in the Lower Columbia River.

The Joint Commenters note that the DEIS confirms the feasibility of clean energy resources taking the place of LSR hydrogeneration in reliably delivering electricity to customers. We also note that the dam breach alternative (MO3) is projected to have more potential for improving life cycle return rates and abundance of ESA listed Snake River salmon and steelhead stocks, in comparison to the Preferred Alternative and the other Multiple Objective Alternatives.

While MO3 clearly provides the best outcome for ESA listed species, the agencies rejected this alternative due to alleged concerns about costs to electricity customers in the region. However, as our comments below demonstrate, the DEIS energy analysis is substantially deficient and has a multitude of shortcomings and omissions.

As a result, the proposed power replacement portfolios for the Preferred Alternative and the Multiple Objective Alternatives – especially MO3 – fall far short of providing optimized, least cost and least risk energy alternatives and significantly exaggerate the cost of clean energy replacement. By relying on deficient analysis to support the Preferred Alternative, the agencies failed to comply with NEPA law and regulations.

1.1 Effects of DEIS Alternatives for ESA Listed Species

The DEIS analysis clearly shows that MO3 results in the most improvement for Lower Snake salmon and steelhead compared to the No Active Alternative and the other Multiple Objective Alternatives (see Table 3-61 below). However, the Preferred Alternative did not incorporate the main elements of

MO3. Instead, the Preferred Alternative chose an approach with allegedly lower net power costs but only a small net benefit for fish.

Table 3-61. Overview of Alternative Analysis

Species	NAA	MO1	MO2	MO3	MO4
Upper Columbia Spring Chinook					
Survival (%)- *McNary to Bonneville*	69.5	70.0	68.7	70.6	71.0
LCM Powerhouse Passage *Rock Island to Bonneville*	3.29	3.08	3.66	2.89	2.53
LCM Smolt to Adult Return Rate (%) *Rock Island to Bonneville*	0.94	0.95	0.93	0.95	0.96
Upper Columbia Steelhead					
Survival (%) *McNary to Bonneville*	65.8	65.6	64.0	66.2	66.1
LCM Powerhouse Passage *Rock Island to Bonneville*	2.72	2.59	2.89	2.52	2.31
LCM Smolt to Adult Return Rate (%)	NA	NA	NA	NA	NA

Species	NAA	MO1	MO2	MO3	MO4
Snake River Spring Summer Chinook					
CSS Survival (%) – *Lower Granite to Bonneville*	57.6	58.3	53.7	68.2	63.5
LCM Survival (%) – *Lower Granite to Bonneville*	50.4	51.0	50.1	60.0	50.7
CSS Powerhouse Passage (PITPH)	2.15	1.74	3.48	0.56	0.34
LCM Powerhouse Passage	2.25	1.88	3.02	0.66	0.49
CSS Smolt to Adult Return Rate (%)	2.0	2.2	1.4	4.3	3.5
LCM Smolt to Adult Return Rate (%)	0.88	0.88	0.90	1.0	0.77
Snake River Steelhead					
CSS Survival (%) – *Lower Granite to Bonneville*	57.1	58.8	44.4	83.1	73.7
LCM Survival (%) – *Lower Granite to Bonneville*	42.7	42.2	40.2	52.7	43.1
CSS Powerhouse Passage (PITPH)	1.96	1.64	3.26	0.46	0.28
LCM Powerhouse Passage	1.73	1.47	2.26	0.42	0.35
CSS Smolt to Adult Return Rate (%)	1.8	1.9	1.3	5.0	3.1
LCM Smolt to Adult Return Rate (%)	NA	NA	NA	NA	NA

DEIS Chapter 3, Table 3-61 (emphasis supplied)

1.2 Effects of DEIS Alternatives for Energy Costs

The DEIS indicates that the BPA wholesale Priority Firm power rate would rise from $35.47/MWh under the Preferred Alternative to $41.23/MWh for BPA-financed replacement power, about a 16.2% increase; or to $37.84/MWh for replacement power financed by BPA's preference customers, about a 6.7% increase.

Table 4-11. Forecast Average Bonneville Wholesale PF Power Rate by Alternative and Scenario ($/MWh, 2019$)

Scenario	NAA	MO1	MO2[1/]	MO3	MO4	PA
Bonneville Finances Zero-Carbon	$34.56	$37.53	$34.28	$41.23	$43.32	$35.47
Region Finances Zero-Carbon		$36.83		$37.84	$40.88	
Bonneville Finances Conventional Least-Cost		$36.64		$37.88	$42.70	
Region Finances Conventional Least-Cost		$36.14		$37.41	$39.87	

DEIS Appendix H, Table 4-11 (emphasis supplied)

As our comments below will demonstrate, the DEIS energy analysis is based on an incomplete and incorrect analysis for selection of an optimized, least cost/least risk replacement power portfolio for MO3, leading to significantly overstated costs than would be the case with a comprehensive and accurate energy analysis, for the following reasons:

- The DEIS energy analysis falls short of widely accepted industry standards for energy system resource analysis and planning and, for that reason, fails to meet the requirement of taking a "hard look," under the National Environmental Policy Act and applicable court decisions, at the relevant and important issue of power replacement to accompany dam breach as a means of restoring fish populations.
- The DEIS energy analysis leaves policymakers and Northwest residents with inadequate and unreliable information to make informed decisions regarding the dams and the energy options available to them.
- The DEIS energy analysis significantly overstates the cost of replacing the power and services currently provided by the dams.
- Thus, the DEIS energy analysis materially overestimates the net costs and resulting rate impacts on electricity consumers for MO3, the most beneficial of the alternatives considered for fish protection and recovery.

The detailed discussion below explains why the Joint Commenters have arrived at these conclusions and why we believe there remains a need for a rigorous and thorough study examining the cost and efficacy of affordable clean energy alternatives before the agencies complete the Final EIS process and issue their Records of Decision.

1.3 Context of the Joint Commenters' Comments

The CRSO DEIS energy analysis is briefly summarized in the Executive Summary, described extensively in Chapter 3, especially Section 3.7, Power Generation and Transmission, with supporting detail particularly in Appendix H (Power and Transmission), Appendix I (Hydroregulation), Appendix J (Hydropower) and Appendix Q (Cost Analysis).

By "energy analysis" here and below, the Joint Commenters refer to the assessment and discussion in the DEIS relating to hydrogeneration and transmission operations providing energy service from the Columbia River System to the preference customer utilities of the Bonneville Power Administration, as well as to the Northwest region and beyond, considering the No Action Alternative, the Preferred Alternative and the four Multiple Objective Alternatives.

In this comment, the Joint Commenters focus on the Preferred Alternative (PA) and Multiple Objective Alternative 3 (MO3), often referred to as the "dam breaching" alternative. The key element of MO3 is the breach of the four Lower Snake River dams (Little Goose, Lower Monumental, Lower Granite and Ice Harbor) and retirement of their respective hydropower generation and related facilities. MO3 also includes additional spill operations at the four Lower Columbia CRS hydro projects and other related measures.

Under MO3, dam breach would return the Lower Snake River to a free-flowing condition connecting the lower Columbia River to substantial salmon and steelhead habitat throughout southeast Washington, northeast Oregon and central Idaho. The DEIS demonstrates that MO3 has, by a substantial margin, the highest likelihood of assisting wild salmon and steelhead stocks currently listed as threatened or endangered under the Endangered Species Act (ESA) to achieve the life cycle viability and abundance levels needed for their protection and potential recovery

To achieve benefits for Snake River basin fish and related environmental benefits, the dam breach under MO3 would also require the retirement of the hydropower facilities in the Lower Snake River dams and, consequently, replacement of the energy services they currently provide. These measures may be needed to support continuing achievement of the Bonneville Power Administration's statutory and contractual obligations, including its preference customer requirements, and for other purposes, although we have no information upon which to determine exactly what energy services need to be replaced to meet BPA's statutory and contractual obligations based on the DEIS analysis.

Lower Snake River dam breach, hydropower retirement and replacement power strategies have been the focus of numerous previous studies, including the Lower Snake River Juvenile Salmon Migration Feasibility Report/Environmental Impact Statement[1] (2002 LSR EIS). The Joint Commenters reviewed this study and others conducted over subsequent years.

1.4 NWEC/ICL Scoping Comments

The Joint Commenters review of the CRSO DEIS uses the scoping comments submitted on February 7, 2017 by the NW Energy Coalition and the Idaho Conservation League ("NWEC/ICL Scoping Comments") as a basis to assess the Preferred Alternative and MO3 energy analysis. That submission is submitted along with these comments for reference.

In the Scoping Comments, NWEC and ICL proposed that the CRSO EIS energy analysis be conducted in accordance with widely accepted practices for utility integrated resource planning (IRP), using a scenario assessment approach, a combination of advanced computer modeling tools and expert judgment to provide a fully optimized energy portfolio selected with respect to a least cost/least risk perspective. This combination of elements, based on longstanding principles and practices of IRP analysis, is needed to effectively assess programmatic alternatives for achieving the energy oriented outcomes defined for the CRSO EIS.

The NWEC/ICL Scoping Comments provided the following summary of recommendations:

- Ongoing support by an independent technical review panel consisting of the Agencies and a broad range of stakeholders, as well as ongoing public input to assure the full range of information and experience can be provided to the assessment.

[1] https://www.nww.usace.army.mil/Library/2002-LSR-Study/

- Evaluation of the current operations of the LSR dams within the context of the Columbia River System, the Northwest regional power system, and the Western Interconnection.
- Assessment and comparison of continued operation of the LSR dams and potential alternative resource portfolios that could better meet CRS responsibilities while minimizing or eliminating environmental impacts and meeting all federal statutory and regulatory requirements. Alternatives to be considered should include:

  (1) continued operation of the LSR dams (no action alternative);

  (2) reduced operation of the LSR dams to provide additional spill for fish passage, including a resource portfolio of replacement energy resources;

  (3) full replacement of the LSR dams with a range of potential resource alternatives.
- Consideration of the full range of electric services provided by the LSR dams and alternative portfolios – energy, capacity, flexibility and reliability – from the perspective of electric system requirements, not merely the potential output of an electric resource, as well as their environmental costs and benefits.
- Utilization of transparent, consistent and commonly accepted methods, inputs, metrics and analysis.
- Consideration of future system conditions through a scenario assessment framework, to assess potential changes in energy demand, resource availability and cost, economic trends, energy policy, climate change and other key factors.
- Consideration of ongoing changes and improvements to the Columbia River System, Northwest power system and Western Interconnection.
- Balancing the costs of all alternative actions against the risks inherent in any forward looking assessment, including environmental costs and benefits.

  NWEC/ICL Scoping Comments at 2-3

First, the NWEC/ICL Scoping Comments proposed that the energy assessment be conducted with assistance from a technical review team, similar to the Hydropower Impact Team that assisted with the 2002 LSR EIS.[2] That team included 16 subject matter experts from the US Army Corps of Engineers,

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[2] Lower Snake River Juvenile Fish Mitigation Feasibility Study: Technical Report on Hydropower Costs and Benefits, Drawdown Regional Economic Workgroup: Hydropower Impact Team, March 1999, https://www.nww.usace.army.mil/portals/28/docs/environmental/drew/powerdoc.pdf

the Bonneville Power Administration, other federal agencies, the Northwest Power and Conservation Council, utilities, industry representative and the NW Energy Coalition.

Such a technical review had proven its worth for the 2002 LSR EIS and could assist in defining the methods and reviewing the results of the DEIS energy assessment to consider alternative federal actions to comply with NEPA and ESA requirements in a complex and fast-changing CRS and regional electric power system context. And as further explained below, utility integrated resource planning (IRP) generally includes a stakeholder technical review process to provide guidance, concepts and data for the planning process.

Second, a key element of comprehensive energy analysis is the consideration of a wide range of alternative resource options and future scenarios of supply, demand and system conditions. As stated in the NWEC/ICL Scoping Comments:

> Considering a range of alternatives to the proposed action "is the heart of the environmental impact statement" and the action agencies must "rigorously explore and objectively evaluate all reasonable alternatives." 40 C.F.R § 1502.14. This evaluation must be based on "accurate scientific analysis, expert agency comments, and public scrutiny." 40 C.F.R. § 1500.1(b). Moreover, "Agencies shall insure the professional integrity, including scientific integrity, of the discussions and analyses in environmental impact statements." 40 C.F.R. § 1502.24.
>
> *NWEC/ICL Scoping Comments at 5*

As the NWEC/ICL Scoping Comments observed, substantial changes have occurred within the Columbia River System and the electric power system of the Pacific Northwest and Western Interconnection in the two decades since the bulk of the energy analysis for the 2002 EIS was conducted in 1997-99.

As discussed below, the DEIS fails to fully consider the effects these changes and others with direct bearing on the CRS, and hence fails to provide the public and decision-makers with relevant and important information to make an informed choice among the alternatives presented in the DEIS. This is a significant failure.

1.5 Lower Snake River Dams Power Replacement Study

Considering the above factors, the NW Energy Coalition commissioned a feasibility study to assess whether Lower Snake River hydropower could be replaced with a clean energy portfolio. The study modeling and assessment were conducted independently by Energy Strategies, a respected technical consulting firm with three decades of experience in transmission and power planning across the Western Interconnection.

The Energy Strategies 2018 study[3] was developed under an innovative framework employing multiple models familiar to and used by power and transmission planners in the Northwest. The study also used the most current available data from authoritative sources such as the Northwest Power and Conservation Council and ColumbiaGrid. The multi-model framework enabled a feasibility analysis of the potential and cost for clean energy resources to replace the energy services of LSR hydrogeneration while preserving Northwest power system resource adequacy and operational reliability. The study concluded that a clean energy replacement for Lower Snake River hydropower would result in an affordable, adequate and reliable Northwest power system.

It is important to note that the Energy Strategies 2018 study was intended to be a feasibility assessment, not a comprehensive review. In commissioning the study, NWEC anticipated that the CRSO EIS, already underway, could provide the comprehensive review needed to comply with the legal requirement of the National Environmental Policy Act to provide a "hard look" at the options available to mitigate the environmental effects of Columbia River System operations, especially on threatened and endangered species in the Lower Snake River basin. Thus, the Energy Strategies 2018 study was intended to provide an input to the DEIS, and to help inform the public and decision-makers in the Northwest.

However, the Joint Commenters below show how the energy analysis conducted for the CRSO review, as reported in the Draft Environmental Impact Statement, falls short of "hard look" required by NEPA.

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[3] Energy Strategies, *Lower Snake River Dams Power Replacement Study: Assessing the technical feasibility and costs of clean energy replacement portfolios,* April 2018, available at: https://nwenergy.org/featured/lsrdstudy/

2. The DEIS Energy Analysis Is Incomplete and Inaccurate

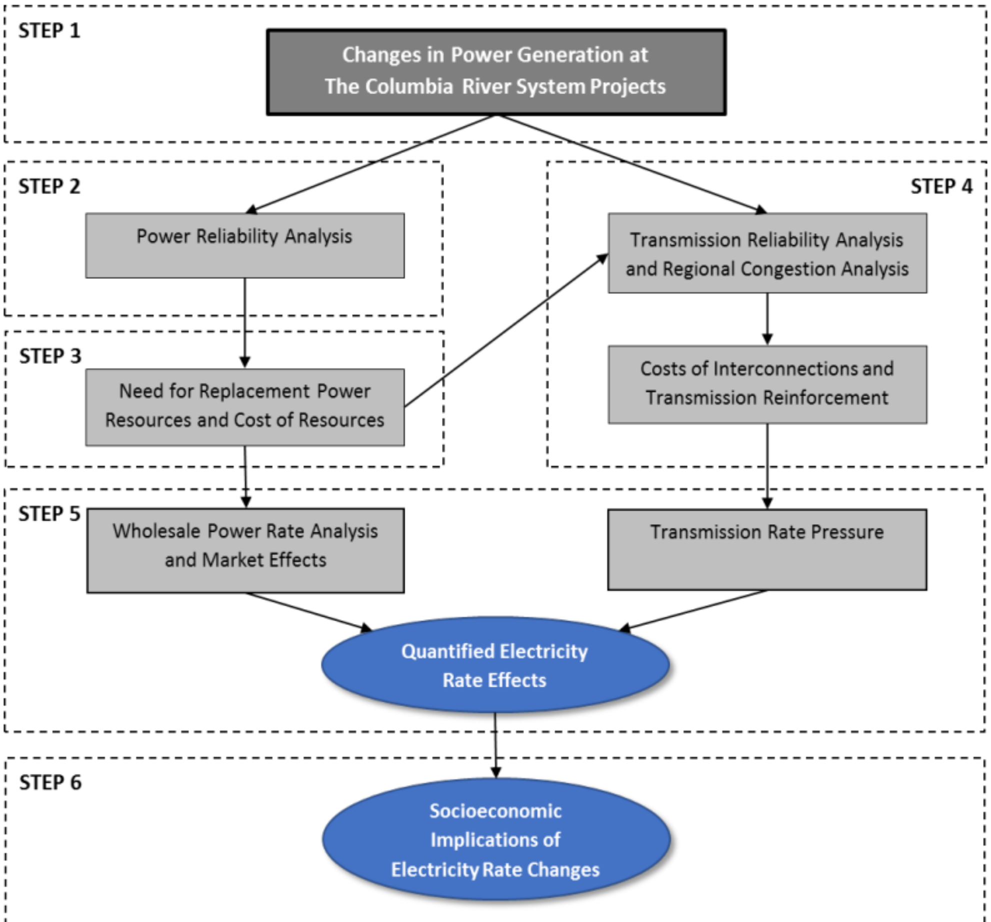

Figure 1-1 Analytical Approach for Evaluating Power and Transmission Effects of the CRSO Action Alternatives

DEIS Appendix H, Figure 1-1

2.1 Deficiencies of the DEIS Replacement Power Analysis

The DEIS energy analysis was conducted according to a multi-step process described in DEIS Appendix H, Section 1.1, Framework for the Analysis. The figure above indicates the basic analysis stages. The focus of these comments is primarily on Step 3, Need for Replacement Power Resources and Cost of Resources, referred to below as the "Replacement Power Analysis."

Because the outcome of Step 3 directly shapes the results achieved in the first stage of Step 5, Wholesale Power Rate Analysis and Market Effects, and Step 6, Socioeconomic Implications of Electricity Rate Changes, the inaccurate and insufficient analysis in the Replacement Power Analysis renders the conclusion of the DEIS energy analysis on wholesale power rates and consumer bill impacts equally inaccurate and insufficient.

The Replacement Power Analysis is the pivotal component of the DEIS energy analysis. This stage of the framework is essential for: (1) fully and accurately estimating the energy system value of the CRS and particularly the hydrogeneration of the four Lower Snake River project; and (2) fully and accurately assessing options for need, cost and performance of replacement power under the Preferred Alternative and four Multiple Objective Alternatives.

As recommended in the NWEC/ICL Scoping Comments and further explained below, an integrated resource planning (IRP) process is the established and longstanding method for this type of comprehensive assessment, as conducted by the Northwest Power and Conservation Council and the region's electric utilities. The Oregon Public Utility Commission summarized its guidelines for IRP analysis as follows:

> Consistent with our guidelines, a utility's IRP must include the following key components:
>
> - Identification of capacity and energy needs to bridge the gap between expected loads and resources
> - Identification and estimated costs of all supply-side and demand-side resource options
> - Construction of a representative set of resource portfolios
> - Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties
> - Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.
>
> *Oregon Public Utility Commission, Order No. 17-386, October 9, 2017*

Below, we review the generally accepted process and the foundational elements for IRP analysis. We compare that approach with the specific steps, data inputs, modeling constraints and other factors employed in the DEIS Replacement Power Analysis, and describe how the DEIS fails to achieve the provide a complete, accurate and rational DEIS energy analysis.

2.2 The CRSO DEIS Does Not Follow Established Methods for Integrated Resource Planning

The electric power system provides essential services and is comprised of critical infrastructure and systems supporting the entire economy, including life, health and safety. Because the system is capital-intensive and must continuously and simultaneously optimize reliability, economic and environmental objectives, integrated resource planning is designed to explore a wide range of possible conditions for electric power demand, resource supply, availability and cost, and coordination of generation, transmission, distribution and demand side components over time.

IRP assessments must consider long time horizons, typically 20 years or more, because of the capital intensity and long operating lifetime of energy resources. Thus, integrated resource planning helps reduce the risks of overinvestment, threats to system reliability, and excessive environmental impacts.

IRP assessment must also consider various forms of system constraints and risks. As a result, IRP assessment includes a rigorous review of alternatives in order to achieve a “least cost/least risk” outcome.

As a consequence, IRP analysis must review existing system resources and consider the need for new resources as the consequence of potential resource retirements, future changes in power demand, and the effects of technology innovation on the cost and availability of new resources. The IRP analysis must then consider a wide range of resource portfolios, including options for new resources, using scenario assessment. Finally, the IRP must assess the range of potential portfolios through the “least cost/least risk” lens and select the new portfolio that can best meet system needs.

As the comments below demonstrate, the DEIS energy analysis fails to achieve any of these requirements. As a consequence, the results greatly overstate the costs and understate the benefits especially of MO3.

Foundational IRP Element #1: Long-Term Assessment

> ***Summary: The DEIS Replacement Power Analysis focuses on a single study year – 2022 – rather than a 20-year planning horizon, in accordance with established best practice.***
>
> ***The DEIS does not explain why the single reference year was chosen for the Replacement Power Analysis and does not explain the choice of 2022 as the reference year.***
>
> ***As a result, the DEIS analysis does not test for a comprehensive range of loads, resources, interconnection and system conditions over time, in accordance with IRP assessment.***

Utility IRP methods generally include a long-term planning horizon; 20 years is often used as providing the best balance between the uncertainties of future system conditions and the long lead times, capital intensity and extended lifetime of new resources, which typically ranges from 5 to 50 years. In the Northwest, the Northwest Power and Conservation Council, Portland General Electric, PacifiCorp, Chelan PUD, Avista Utilities, Idaho Power, Puget Sound Energy, Seattle City Light and many others use 20 years as the time horizon for their IRPs, even when they expect specific resource retirements.

In contrast, the DEIS Replacement Power Analysis uses a single planning year, 2022. By choosing a single reference year, the DEIS energy assessment provides a "snapshot" view that is arbitrary, incomplete and not at all indicative of the dynamic conditions expected for CRS operations over the coming years and decades. This precludes the long-term system assessment required to consider changing conditions for the CRS over many years and decades.

In addition, as discussed at length below, the use of a 2022 reference year is particularly inappropriate for MO3. As a consequence, the replacement power portfolio for MO3 is not adequately assessed and is very likely to have much higher apparent cost than would be the case with a more appropriate starting date and long-term assessment in line with standard IRP practice.

Foundational IRP Element #2: Scenario Assessment

> ***Summary: Unlike standard utility IRP assessment, the DEIS conducts an extremely limited review of scenarios. The DEIS does not explain why this very limited set of scenarios was chosen instead of the multi-factor and more wide-ranging scenario assessment needed for a comprehensive, accurate and sufficient Replacement Power Analysis.***

Using an appropriate long-term time horizon for an IRP assessment enables planner to assess existing and new resources under a wide range of future system conditions, considering changes in electricity demand, climate change, technology innovation, energy markets and other dynamic factors. To facilitate the IRP process, these varying elements are aggregated together as scenarios. The purpose of scenario assessment, broadly speaking, is to test the "feasibility space" of different resource portfolios in meeting future demand requirements under widely varying conditions.

For example, the Northwest Power and Conservation Council's 7th Northwest Power Plan[4] includes more than 20 scenarios, each assessed against 800 futures generated from combinations of regional load and resource projections under conditions. The scenario assessment considers historical temperature, rainfall and Columbia basin hydrosystem conditions, and includes forward projections for fuel (especially natural gas), power market prices, current and future resource costs, and many other factors.

In stark contrast to established best practices, the DEIS energy analysis provides a very limited assessment. The Replacement Portfolio Analysis in Step 3 of the framework, in which the replacement resource mix for each DEIS alternative is selected, effectively has only a single scenario. The subsequent wholesale and retail "rate pressure" analysis in Steps 5 and 6 of the process have a very limited set of sensitivities.

As a result, the DEIS energy analysis, particularly for the crucial portfolio selection in Step 3, does not set forth a rational range of scenarios commensurate with standard IRP practice, and the DEIS does not explain why it failed to do so. Under NEPA, "Agencies shall insure the professional integrity, including scientific integrity, of the discussions and analyses in environmental impact statements."[5] By failing to adhere to established industry practices, this DEIS is not the requisite "hard look" under NEPA.

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[4] Northwest Power and Conservation Council, Seventh Northwest Conservation and Electric Power Plan, February 2016, https://www.nwcouncil.org/reports/seventh-power-plan
[5] 40 CFR § 1502.24.

Foundational IRP Element #3: Resource Portfolio Optimization

> ***Summary: The DEIS does not conduct the iterative, progressive approach to resource portfolio optimization that is key to recommending a robust new resource plan to meet the least cost/least risk criterion.***
>
> ***Instead, the DEIS considers a single, static metric for resource adequacy in a single year, 2022, and does not proceed to any of the other steps considered essential for rational resource optimization in standard utility IRP practice.***

Resource portfolio optimization in a crucial step in the IRP process, and thus a major part of any legitimate energy system plan. Without optimization, it is nearly certain that the resulting resource portfolio will have significantly greater cost, weaker performance and lower system value than it should. While the effort to optimize resource portfolios must be methodical and thorough, a wide range of methods and models can be used to accomplish this key outcome.

The resource portfolio development process must be rigorous, comprehensive and as objective as possible, and must be guided by a careful mix of modeling and expert judgment. As mentioned above, the process for IRP resource portfolio optimization typically starts with development of a wide range of system scenarios and resource portfolios, which are then iterated in stages. At each stage, the range of candidate portfolios is narrowed and re-optimized, leading toward selection of a preferred resource portfolio in the final stage that best meets all relevant criteria and constraints.

An optimized resource portfolio must include a review of both existing and potential new resources, including all their relevant capabilities and costs. The review must assess all current and potential new resources on a comparable basis, using multiple criteria covering capital and operating cost, environmental cost and benefit, and system resource adequacy and operational reliability.

Because energy resources have varying costs, capabilities and effects, they interact differently with the overall power system. The potential contribution of each resource to total system value must be examined in concert with all others. The ultimate measure is not the performance of a given resource on its own, but rather how individual resources interact with the electric system to provide reliable, affordable energy to customers.

IRP resource portfolio optimization includes many performance metrics and constraints. In overview, these include operational reliability, resource adequacy, and energy, capacity and flexibility value.

The resource portfolio development process must be rigorous, comprehensive and as objective as possible, and must be guided by a careful mix of modeling and expert judgment. The outcome must be a preferred resource portfolio that meets least cost/least risk criteria.

As mentioned above, the process for IRP resource portfolio optimization typically starts with development of a wide range of system scenarios and resource portfolios, which are then iterated in stages. At each stage, the range of candidate portfolios is narrowed and re-optimized, leading toward selection of a preferred resource portfolio in the final stage that best meets all relevant criteria and constraints.

In contrast to these established methods, models, data and review processes, the DEIS Replacement Power Analysis, conducts only the most cursory approach to developing replacement power portfolios for the alternatives under consideration. As described more fully below, the DEIS does not explain why the analysis did not incorporate other data and factors that were readily available to the energy analysis to develop robust resource portfolios that could be selected through scenario assessment, portfolio optimization and least cost/least risk screening. The DEIS does not conduct a review of a range of potential resource portfolios, then narrow them down by testing them across a wide range of scenarios over time.

The DEIS does not explain why the alternatives are assessed with respect to a single study year, 2022, rather than the long-term horizon that is standard practice. The DEIS energy analysis therefore has resulted in a materially incomplete, misleading and arbitrary assessment of replacement options for all alternatives presented, and most especially MO3.

Development of DEIS Replacement Power Portfolios

The DEIS describes the Replacement Power Analysis portfolio selection process as follows:

> To determine the optimal mix of resources under each portfolio, this analysis assesses the cost-effectiveness of specific power resources by dividing the total costs by the LOLP benefit. The most cost-effective resources were then added into the GENESYS model until the resulting LOLP reached the No Action Alternative LOLP (6.6 percent).
>
> *DEIS, Appendix H at line 606*

A check against resource adequacy is a key part of any IRP process. But assessing the adequacy of an alternative is fundamentally different than developing that alternative in the first place. The use of a resource adequacy model to develop resource portfolios is not a rational way to match the demanding test of meeting all system requirements over multiple years and decades in a least cost/least risk fashion.

We start by reviewing the loss of load probability (LOLP) metric. The LOLP is a measure of system resource adequacy in a future year. It is a metric that is widely used in the electric utility industry to assess whether sufficient system resources will exist in each operating hour across a year to meet anticipate system demand.

The Northwest Power and Conservation Council developed the GENESYS model two decades ago to assess the resource adequacy of the Northwest regional power system using the LOLP metric as a primary measure. GENESYS is regarded as being the most capable model for that purpose in the Northwest, in particular because of its highly sophisticated emulation of CRS hydrogeneration under a full range of hydrological flow, hydrogeneration and power system conditions.

The Council resource adequacy assessment is updated annually and looks forward five years. The assessment has proven to be highly robust and provides valuable guidance for regional decision makers and the public. However, that assessment only includes existing resources and committed new resources, including the Council's regional energy efficiency target. The annual resource adequacy assessment does not generate and test candidate power portfolios to fill any resource adequacy gap – that effort is considered in the Council's Northwest Regional Power Plan every five years.

The agencies here have ready access to the appropriate tools to develop optimized resource portfolios. To develop the preferred resource mix for the Northwest Regional Power Plan, the Council uses its capital expansion model, the Regional Portfolio Model (RPM). Capital expansion models are the core of IRP assessment, because they simulate power system conditions over the planning time horizon for the scenarios, data, constraints and resource portfolios of a full IRP assessment. Their outputs can be used to iterate, optimize and select the least cost/least risk preferred portfolio. Some capital expansion models are vendor-supplied, while others, like the Council's RPM, are internally developed. Regardless of source, the established industry practice is to use capacity expansion tools to develop alternative portfolios, and then use resource adequacy tools to assess these alternatives. The DEIS skipped this step to develop a robust set of alternatives and thus fails to comply with NEPA.

The DEIS Replacement Power Analysis consisted of three steps.

First, GENESYS was used to derive loss of load probability (LOLP) values for the existing Northwest power system as modeled in 2022 under the median water scenario. This resulted in a 6.6% annual LOLP metric. This is a static annual value for the single year of 2022 and does not incorporate future changes of loads, resources, climate change and future hydro variability, changes in western power markets and many other factors that must be considered in IRP analysis.

Second, changes to resource operation in the existing system were loaded into GENESYS and run for each of the Multiple Objective Alternatives. These changes included modified generation patterns at the CRS generation facilities in accordance with the hydroregulation study for each alternative. Overall, this resulted in the changes to average annual LOLP in 2022 (illustrated in column two of Table ES-10 below), before considering power replacement portfolios.

Table ES - 10. NW-US System Zero-Carbon Portfolio and Associated Change in Carbon-based Generation for the Base Case without Additional Coal-Plant Closures

Alternative	LOLP (percent)	Least carbon capacity added to reach 6.6% LOLP (MW)	Change in existing Carbon-producing Generation (aMW)
MO1	11.2	1,200 Solar/600 DR	-70
MO2	5.0	-600 DR (avoided) -660 Wind (avoided) -250 Solar (avoided)	-428
MO3	13.9	2,550 Solar/600 DR	457
MO4	29.6	5,000 Solar/600 DR	70
PA	6.5	N/A	142

DEIS Appendix J, Table ES-10

Third, resources by type (natural gas, wind, solar, battery storage, demand response) were added in economic merit order and run in the GENESYS model until the annual LOLP in 2022 again reached the 6.6% level. Note that this third step was only conducted for MO1, MO3 and MO4, because MO2 resulted in a lower LOLP than the baseline.

This third step constitutes the full and entire process of developing the power replacement portfolios in the DEIS. No additional iteration or optimization whatsoever was conducted. This process is not the robust development and analysis of alternatives required by NEPA. The agencies do not explain how the cost-effectiveness for each resource type was determined and how the resources were assembled in economic order sequence to create each replacement power portfolio. Such details would normally be explained at length during a standard IRP process.

The process described fails to select the best replacement portfolios considering their interaction with the entire system, as would an adequate IRP assessment

As a result, it is nearly certain that the net costs of the replacement power portfolios resulting from the DEIS Replacement Power Analysis significantly exceed what a fully optimized review would accomplish. The DEIS fails to explain either why its limited approach is rational and reliable, nor why it did not take the steps of a standard IRP analysis to ***weigh*** and optimize the many factors over the long duration time horizon needed to select the lowest cost and least risk replacement portfolio, especially for MO3.

Foundational IRP Element #4: Least Cost/Least Risk Assessment

> ***Summary: The DEIS does not explain why the Replacement Power Analysis does not define least cost/least risk criteria nor construct the power replacement*** portfolios ***to include all factors necessary to achieve those criteria. In particular, the DEIS energy assessment does not explicitly address system risk as well as system cost.***
>
> ***Therefore, the DEIS does not conduct a rational or robust least cost/least risk assessment across a full planning horizon of 20 years or more.***

Utility IRP analysis in the Pacific Northwest generally engages in some form of least cost/least risk assessment. That is, rather than merely solving for a single objective function over time, such as minimizing cumulative system cost, IRP modeling must also account for multiple elements of risk. Among these are operational reliability, longer term resource adequacy, and financial risk. The Oregon Public Utility Commission order on the Portland General Electric 2016 Integrated Resource Plan describes the industry standard for least cost-least risk planning:

> The IRP is a road map for providing reliable and least cost and least risk electric service to the utility's customers, consistent with state and federal energy policies, while

> addressing, and planning for, uncertainties. The primary outcome of the process is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."
>
> *Oregon PUC Order 17-386 at 3*

Above we describe the industry best practice for developing alternative resource portfolios. In sum: Tradeoff analysis and expert judgment must be combined with computer modeling to achieve a fully optimized system portfolio that appropriately balances cost and risk.

To accomplish this result, a co-optimization approach is employed to find the best balance between minimizing production cost over time (least cost) while also minimizing variation in both direct and externality risks, usually through a proxy cost factor (least risk).

There are many recognized methods for achieving a least cost/least risk planning result and defining a new resource portfolio, but the DEIS employed none of them.

For example, the Northwest Power and Conservation Council uses its Regional Portfolio Model (RPM) to construct the preferred least cost/least risk resource mix for its 20-year resource portfolio and associated 5-year action plan, all of which are updated approximately every five years in the Northwest Regional Power Plan.

The RPM operates in quarterly steps over a 20-year time horizon. For each of more than 20 scenarios in the 7th Northwest Power Plan, the RPM model generated about 800 futures representing ranges of load, resource and market price conditions across the 80 time steps, incorporating additional elements for risk assessment such as stochastic shocks to market prices. The RPM model selects the optimal mix of existing and new resources across all time steps for each scenario and aggregates the results to a cost metric and a risk metric.

The complete set of scenario cost and risk metrics across the 800 futures is then plotted to show an "efficient frontier" where cost and risk are minimized. Finally, the Council reviews those scenarios falling closest to the efficient frontier and applies further analysis, extensive stakeholder input and expert judgment to select the future resource portfolio included in the 20-year regional plan and the associated 5-year action plan.

In contrast, to select the new resources for the Preferred Alternatives and the four Multiple Objective Alternatives, the DEIS Replacement Power Analysis only assesses baseline conditions for the single study year of 2022, rather than a multi-decade study period with a comprehensive scenario assessment. The replacement power portfolios for each alternative consist of only two – the "least cost conventional" portfolio and the "zero-carbon" portfolio. Those portfolios were selected to return MO1, MO3 and MO4 to the 6.6% LOLP baseline of the No Action Alternative but not to meet any other important performance criteria and constraints.

The set of two portfolio options for each DEIS alternative is far more limited than the wide range of portfolios typically considered in IRP analysis. Rather than assessing the full range of energy, flexibility and other criteria to steer toward a least cost/least risk portfolio, the criterion for selection of the DEIS replacement portfolios is a single factor – resource adequacy as denoted by the LOLP metric. This is not a rational, accurate or sufficient step to create an optimized, least cost/least risk power replacement portfolio.

In conclusion, as a result of the omissions and deficiencies in the DEIS Replacement Power Analysis for MO3, the results are incomplete and inadequate. Consequently, the rate pressure analysis in Step 5 and the socioeconomic impact analysis in Step 6 of the framework analysis, which are based entirely on the Power Replacement Analysis, are likewise incomplete and inaccurate.

3. The Replacement Power Analysis Is Limited to A Single Study Year

As described in the previous section, Step 3 of the CRSO DEIS energy assessment framework, the Replacement Power Analysis, includes a comparative analysis of the CRS system performance of the proposed six alternatives based on a single year system assessment for the year 2022.

In contrast, the subsequent "rate pressure" analysis in Step 5 and the socioeconomic analysis of rate effects in Step 6 are conducted over long-term time horizons. For example, the DEIS states, "the quantitative regional economic effects are reflected through changes in rate pressure for residential, commercial, and industrial ratepayers over a 20-year timeframe (2022 to 2041), with a qualitative assessment of whether and how effects may persist beyond that timeframe." DEIS Chapter 3 at 24966.

3.1 The Choice of the Year 2022 is Infeasible and Inappropriate for Assessment of MO3

Even under the most rapid process conceivable, LSR dam breach and hydrogeneration retirement cannot possibly be completed in 2022. The DEIS defends the use of the 2022 date as follows:

> The construction costs for the structural measures were assumed to be implemented over the first two years of the project (2021 and 2022), consistent with guidance provided by the co-lead agencies. Although some of these measures, especially the dam breaching measures, may take a number of years to implement or may not start for a number of years (pending further studies), it was necessary to provide a consistent time-frame for implementation in the evaluation to compare across the alternatives.
>
> *DEIS Appendix Q at Q-3-2*

While we agree that using a consistent time-fram is important, the DEIS focus on 2022 is arbitrary because, as the agencies admit, dam breach under MO3 is not be possible by 2022. Many financial, engineering, contractual, legal and other steps are needed to accomplish dam breach, hydropower retirement and related activities, as well as acquisition of the replacement power portfolio. Completion of these activities under MO3 would take several years to put in place.

The choice of the starting year for the Replacement Power Analysis is consequential. Compared to a later year that is closer to the first feasible time that MO3 can be implemented, many factors in the regional power system and CRS will have changed. Of particular importance to the anticipated cost for MO3, the ongoing decline of clean energy resource costs will proceed further because of technology innovation and policy such as the Clean Energy Transformation Act in Washington,[6] decreasing the actual cost of the replacement portfolio for MO3. Furthermore, the data and models available for the DEIS energy analysis can easily accommodate a shift in the reference year for MO3.

The DEIS does not provide any rationale for the use of a single reference year for the Replacement Power Analysis and other purposes, includes information to contradict that this is a reasonable date, and still proceeds with the analysis of a flawed single reference year that biases the results of the analysis. In conclusion, the DEIS's explanation that use of a single reference year, 2022, is needed for consistency across Alternatives is inadequate given the nature of resource planning.

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[6] See Washington State Department of Commerce, Clean Energy Transformation Act (CETA), https://www.commerce.wa.gov/growing-the-economy/energy/ceta/

4. The Replacement Power Analysis Has Numerous Gaps and Deficiencies

In addition to the failure to use appropriate tools and metrics, the DEIS does not use accurate information on the availability, cost and performance resources available to address the issue. The Replacement Power Analysis portfolio results are summarized in DEIS Appendix H, Table 2-2, as depicted below. The resource portfolios resulting from the DEIS Replacement Power Analysis show very limited diversity and leave out resource types known to have significant value in the Northwest, including advanced energy efficiency and wind power. There are many additional omissions from the analysis, as described below.

Table 2-2. Potential Replacement Resource Portfolios by Scenario

<table>
<tr><th>Resource Portfolio</th><th>MO1</th><th>MO2[1/]</th><th>MO3</th><th>MO4</th></tr>
<tr><td>Zero-Carbon</td><td>600 MW demand-response and 1,200 MW solar</td><td rowspan="2">Avoided build of 440 MW of simple cycle natural gas or 250 MW solar, 660 MW MT wind, and 600 MW demand response[1/]</td><td>600 MW demand-response, 2,550 MW solar, and 1,250 MW of battery storage</td><td>600 MW demand-response and 5,000 MW solar</td></tr>
<tr><td>Conventional Least-Cost</td><td>560 MW simple cycle natural gas</td><td>1,120 MW combined cycle natural gas</td><td>3,240 MW simple cycle natural gas</td></tr>
</table>

1/ MO2 would improve power system reliability relative to the No Action Alternative; therefore, the analysis identifies potential "avoided builds" of replacement resources.

4.1 The Obligation to Acquire Energy Efficiency

The Replacement Power Analysis portfolios use inadequate information for energy efficiency resource availability. This is a serious omission in the DEIS energy analysis and raises important issues with respect to the Northwest Power Act. The DEIS purports to address this issue as follows:

> Table 2-3 provides the per unit capital costs ($/kW) of the replacement resources identified for each alternative and portfolio. The analysis used the midpoint of the costs for the resource replacement selection. The NW Council's 2022 load forecast that was used for the LOLP reliability modeling include all cost-effective conservation. According to the 7th Power Plan, by 2022 there is 1,871 aMW of conservation available to the region price at $80 per MWh or below. There is an additional 148 aMW of conservation price at over $80 dollars per MW and half of it is price at over $140 dollars per MWh. This conservation has a higher cost than the other resources that were developed for the MOs, and therefore were not included.
>
> *DEIS Appendix H at line 680*

However, analysis for the 7th Power Plan was primarily conducted in 2015 based on data available up to that time. It has been five years since the 7th Plan energy efficiency analysis was conducted, and a further two years until the DEIS Replacement Power Analysis single study year of 2022. Furthermore, as extensively discussed above, resource acquisition to cover reductions in hydrogeneration under MO3 would occur in some later year, during which time additional cost-effective energy efficiency resources are likely to become available.

For the last several decades, energy efficiency has benefitted from rapidly emerging technology innovation in residential, commercial and industrial energy use. These improvements in opportunities for energy efficiency are not easily captured over long time horizons. Therefore, conservation assessments from five years ago are outdated and of limited and uncertain usefulness for the DEIS Replacement Power Analysis. Furthermore, the Council's analysis provides estimates not just for a single year, but for the changing costs and availability of energy efficiency over time.

However, the DEIS did not employ such data and methods, nor does the DEIS explain why such steps were not taken to incorporate the most accurate available information. This calls into question the validity of the price and availability of the energy efficiency resource used in this analysis.

In addition, the amount of cost-effective conservation chosen is a function of all the other aspects of any given scenario and portfolio. According to the DEIS Replacement Power Analysis, under alternatives MO1, MO3 and MO4, CRS hydrogeneration would decline, and therefore regional power supply would fall relative to demand. As that occurs, costs will rise and the cost-effectiveness limit for replacement resources will go up. The Council's RPM model takes all of this into account, adjusting for market price effects as it assesses, iterates and optimizes the selection of resources into its resource portfolio.

But instead of incorporating all the dimensions of the Council's energy efficiency analysis, the DEIS chooses a crude average cost. This likely falls short of full assessment of additional cost-effective energy efficiency that could be included in the DEIS replacement portfolios, thus decreasing their cost. The DEIS does not explain the reasons for not using the full Council analysis.

4.2 Overestimated New Resource Costs

The DEIS Replacement Power Analysis relies on supply resource cost data from the Council's 7th Northwest Regional Power Plan and its 2018 Midterm Assessment. DEIS Chapter 3 at line 673. These resource costs are outdated and more recent cost data sources were available for the DEIS analysis, but were not used.

For example, the National Renewable Energy Laboratory launched its Annual Technology Baseline (ATB),[7] which provides a sophisticated, freely available, fully documented framework for assessing future resource costs that includes estimation of technical innovation, policy drivers and market acceptance. The ATB has rapidly become an authoritative source for electric generation and battery storage resource cost estimates.

Along with using stale information on costs and performance, the DEIS further overstates the cost of MO3 by electing to start in 2022, a date the agencies themselves say is not a reasonable starting point. Application of such outdated resource pricing further overstates the overall cost of MO3. If a more feasible starting point is chosen, the continually declining costs of clean energy replacement resources will materially decrease the cost of MO3.

Solar photovoltaic (PV) resources illustrate these concerns. While PV systems have been commercially available since the 1970s, over the last decade PV has rapidly ascended to become a leading source of renewable energy, along with wind power. This has been driven by rapid technological innovation and development of global supply changes, and as a result costs have rapidly decline.

Technical innovation continues to emerge with PV systems. In the last two years, bifacial PV modules have rapidly become a significant fraction of the market, and are poised to become the dominant format within the next few years. Because bifacial modules collect both direct insolation and reflect surface energy, it is estimated they will add about 10% to output at little or no incremental cost.[8]

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[7] Annual Technology Baseline, National Renewable Energy Laboratory, atb.nrel.gov.
[8] National Renewable Energy Laboratory, "Bifacial Solar Advances with the Times—and the Sun," February 2020, https://www.nrel.gov/news/features/2020/bifacial-solar-advances-with-the-times-and-the-sun.html

Secondly, while PV considered by itself is a variable energy resource, considerable effort is being made to improve its performance, decrease output variability and match system demand more precisely. These most recent and important development is the rapid emergence of integrated hybrid PV-battery storage power plants. Advances on the hybrid front have been so rapid that there was almost no cost and performance data available in 2018, but now it is estimated that hybrid PV-storage projects are nearly half of the interconnection queue in California. The potential was already apparent in mid-2019, when the California Independent System Operator noted that approximately 41% of the total capacity currently seeking interconnection to their system was hybrid resources, mostly consisting of PV-battery configurations.[9]

At the same time, PV-battery hybrid resource costs have declined at unprecedented rates. Two recent articles considered the costs of a new PV-hybrid project being constructed under contract with the Los Angeles Department of Water and Power (LADWP). The project will consist of 400 MW of PV and 300 MW/1200 MWh of battery resources. Analysts suggest the value of the project will be under $40/MWh for energy and $127/kW-year for capacity, below the cost of a new gas peaker power plant.[10]

While the costs for such hybrid projects in the Northwest will be higher due to the somewhat less favorable solar resource in this region, their value will be considerable given the potential for co-optimization with the storage and flexibility capabilities of the CRS, while providing adding to overall system energy, capacity and resource adequacy, especially during the late summer when demand is high and the spring freshet has depleted and hydrogeneration potential is very limited.

DEIS Replacement Portfolio Analysis failed to incorporate these widely known and established industry trends and instead relied on stale information that consistently overstates the costs of the alternatives.

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[9] CAISO, “Hybrid Resources Initiative: Issue Paper Stakeholder Meeting,” July 22, 2019, http://www.caiso.com/InitiativeDocuments/Presentation-HybridResources-IssuePaper.pdf

[10] Energy Storage News, "Battery storage at US$20/MWh? Breaking down low-cost solar-plus-storage PPAs in the USA," March 20, 2020, https://www.energy-storage.news/blogs/battery-storage-at-us20-mwh-breaking-down-low-cost-solar-plus-storage-ppas; and EnergyGPS, "Grateful for Reliability, April 3, 2020, https://www.energygps.com/Newsletter/b/Newsletter-Grateful-for-Reliability-1620014

The DEIS analysis adopts a PV capital cost of $1,350 to $1,500/kW (2019$). DEIS Appendix H, Table 2-3. Those costs are applied to the single study year of 2022. By that time, costs are likely to decline by a significant amount, reflecting deeply embedded declining cost trends over many years, yet the DEIS made no attempt to account for that. Assessments seeking to assess future technical, performance and cost trajectories for resources undergoing profound innovation such as PV have several analytical tools at their disposal. Here we discuss and apply two that are particularly relevant to future resource cost projections – at least one of which should have been employed in the DEIS energy analysis.

The first is a technique is known as experience curve analysis (often called learning curve analysis, though that term is more limited in applicability). This relies on the robust and well documented process through which technologies undergoing technical innovation decline in cost by a fixed factor, known as the learning rate, for a given amount of aggregate market expansion. Research by the Santa Fe Institute demonstrated the robust performance of experience curve assessment in considering future resource cost trajectories across 62 industries.[11]

In 2013, NWEC submitted a paper to the Western Electricity Coordinating Council (WECC), describing the technique and use of experience curve analysis specifically with regard to PV technology and markets.[12] In general, as the global installed capacity of PV doubles in size, cost comes down by about 20% for modules and 15% for balance of system costs. That observation has remained robust since a 1978 analysis by the Solar Energy Research Institute (now NREL) to the present time.

To illustrate the importance of the deficiency in the DEIS energy analysis of future resource costs, we use these two methods described above to assess the future costs of PV resources in relation to the costs in the DEIS. As mentioned, the DEIS adopts the Council's 2018 estimate of $1,350 to $1,500/kW-ac (2019$) for grid-scale PV in 2022. To simplify the explanation, we assume a midpoint

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[11] Nagy B, Farmer JD, Bui QM, Trancik JE (2013) Statistical Basis for Predicting Technological Progress. PLoS ONE 8(2): e52669. https://doi.org/10.1371/journal.pone.0052669
[12] NW Energy Coalition, "Experience Curves and Solar PV," September 3, 2012, available at: https://app.nwcouncil.org/media/6867808/2012-09-03-nwec-experience-curves-and-solar-pv.pdf

value of $1,425/kW-ac. A full assessment within an IRP analysis would consider ranges of future costs as part the scenario, portfolio optimization and least cost/least risk analysis.

NWEC's experience curve assessment assumes that the global PV market will double in size by 2022 and double again by 2026, a possible starting point for MO3. This results in a capital cost of $1,193/kW-ac in 2022 and $1,000/kW-ac in 2026. NREL's ATB – referred to above as the industry standard for projecting future resource costs – projects a midpoint cost range for PV of $1,214/kW-ac in 2022 and $1,071/kW-ac in 2026. There is good agreement between the simplified experience curve method and the more detailed ATB method. The table below compares these results to the DEIS analysis.

Source	PV cost per kW-ac (2019$)	Change
DEIS 2022	$1,425	
NWEC experience curve 2022	$1,193	-16%
NREL ATB 2022	$1,214	-15%
NWEC experience curve 2026	$1,000	-30%
NREL ATB 2026	$1,071	-25%

Within an IRP context, the experience curve and ATB methods can provide valuable guidance for assessing resource costs over time. As illustrated here, projecting out-of-date resource costs forward into the future risks greatly overstating costs for resource portfolios. The DEIS does not explain why the agencies used stale data and methods for assessing future resource costs in the Replacement Power Analysis. As a result of this failure to insure the professional and scientific integrity of the analysis, the DIES significantly overstates the apparent cost of the replacement portfolios. This failure undercuts the selection of the Preferred Alternative.

4.3 Hybrid Solar-Battery Storage

As noted in DEIS Appendix H, Table 2-2, the “zero carbon” replacement power portfolio for MO3 includes 2,550 MW of solar with 1,250 MW of battery storage.

First, the analysis fails to provide any explanation of why 1,250 MW is the right amount of incremental storage, and notes that this was done “last” in the analysis as an add-on. Further, it does not consider the perspective that the LSR dam attributes “lost” are the same ones that the rest of the CRS system might have in excess if significant amounts of solar and wind are developed on the system.

Second, the DEIS does not consider additional storage resources when determining how much solar and demand response are necessary to return the system to the LOLP baseline. This means the analysis of MO3 is likely overbuilt from a capacity perspective. To properly build the portfolio, the DEIS should have calculated the flexibility need created, added storage to provide that, then counted this storage in the LOLP analysis to determine what additional solar/wind capacity is required to return the system to the benchmark LOLP. As a result of this one error, the MO3 portfolio likely should have had either less solar, less storage, or less of both, resulting in a material reduction in portfolio cost.

Third, as shown in DEIS Appendix H, Table 2-3 below, the DEIS Replacement Power Analysis includes a cost $2,568/kW for hybrid solar plus battery storage resources, based on an October 2019 staff presentation to the Northwest Power and Conservation Council. However, the DEIS applies this value in an incorrect fashion. As shown below, the Council presentation was based on a reference facility with equivalent solar nameplate capacity and storage capacity–a 100 MW-ac solar plant and 100 MW/400 MWh battery facility.

Table 2-3. Capital Costs of Replacement Resources (2019$)

Resource Type	Cost ($/kW)
Solar	$1,350 to $1,500
Wind	$1,500 to $1,700
Combined Cycle Gas	$1,100 to $1,300
Simple Cycle Gas	$500 to $650
Reciprocating Engine	$1,250 to $1,450
Solar Co-Located with DC-Coupled Battery[1/]	$2,568

2021 Plan Reference Plant: Solar + Battery Storage

	Solar + Battery Storage
Configuration	100 MW_{AC} Solar Co-Located with DC-Coupled 100 MW, 400 MWh Battery
Capacity (MW)	100
Energy (MWh)	200
Round Trip Efficiency	88%
Financial Sponsor	IOU
Economic Life (years)	15
Overnight Capital Cost ($/kW)	2568
Fixed O&M Cost ($/kW-yr)	31

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However, in the DEIS Replacement Power Analysis, the hybrid resource chosen, as shown in Table 2-2, Appendix H above, is 2,550 MW solar and 1,250 MW of battery storage. The DEIS analysis does not explain whether the battery capability is the same as in the Council analysis, that is, 4-hour storage (100 MW/400 MWh).

That said, use of the Council's cost for solar and battery storage significantly overstates the hybrid resource cost for MO3, because 2,550 MW of solar is paired with 1,250 MW of battery capacity instead of the one-for-one cost basis of the Council's estimate. Because battery storage is still relatively expensive, this considerably overweights the combined resource cost per kW. This apparent error should be corrected in the Final EIS.

Furthermore, even since the Council's analysis in 2019, hybrid solar and battery storage project costs have quickly fallen and media reports indicate similar systems may now have capital costs at least one third less, or approximately $1,700/kW.

NWEC estimates a correction to the DEIS solar+battery cost could reduce the annualized value of the capital cost of the "zero carbon" portfolio for MO3 (Appendix H, Table 2-4) by more than one quarter, from $389 million to $270 million per year; and "rate pressure" on BPA wholesale power rates and consumer electric bills would drop accordingly.

Table 2-4. Annual Replacement Resource Costs by Financing Scenario and Replacement Portfolio (thousands, 2019$)

Financing Scenario	Resource Portfolio	Average Annual Costs	MO1	MO2	MO3	MO4	PA
Region	Conventional Least-Cost	Capital Costs	$27,000	Avoided build of 440 MW of Gas or 250 MW solar, 660 MW MT wind, and 600	$138,000	$156,000	Neither replace-ment resources nor
		Variable Costs[1/]	$7,000		$96,000	$42,000	
	Zero-Carbon	Capital Costs Demand Response	$131,000 $30,000		$389,000 $30,000	$547,000 $30,000	

Financing Scenario	Resource Portfolio	Average Annual Costs	MO1	MO2	MO3	MO4	PA
Bonneville	Conventional Least-Cost	Capital Costs	$27,000	MW demand response[/2]	$138,000	$156,000	avoided build
		Variable Costs[1/] and 3/	$16,000		$112,000	$91,000	
	Zero-Carbon	Capital Costs Demand Response	$131,000 $20,000		$389,000 $20,000	$547,000 $20,000	

4.4 Demand Response

"Demand response" refers to contractual and/or rate design methods to reduce electricity end use at times of system peak demand, usually very limited number of hours per year.

Demand response provides high value because otherwise the most expensive reserve generation must be activated to meet system peaks and provide other flexibility for a limited amount of hours in a year. These capabilities are particularly important in comparing a replacement resource mix to the energy services provided by LSR hydrogeneration.

The DEIS Replacement Power Analysis limits demand response to 600 MW. The DEIS states:

> The CRSO base case analysis uses the NW Council's 7th plan for costs and amounts of achievable demand response. Consistent with the 7th Power Plan's estimates, the

> analysis assumes 400 MW of demand response developed in the near-term by Bonneville, in partnership with Bonneville's power customer utilities, and another 200 MW of demand response developed by regional investor owned utilities.
>
> *DEIS Appendix 3 at line 25495*

However, this is not "consistent with the Council's estimates." The Council 7th Plan recommendations identified 600 MW of demand response as the minimum amount available, not the ceiling assumed in the DEIS:The Council's assessment identified more than 4,300 megawatts of regional demand response potential. A significant amount of this potential, nearly 1,500 megawatts, is available at relatively low cost; less than $25 per kilowatt of peak capacity per year.

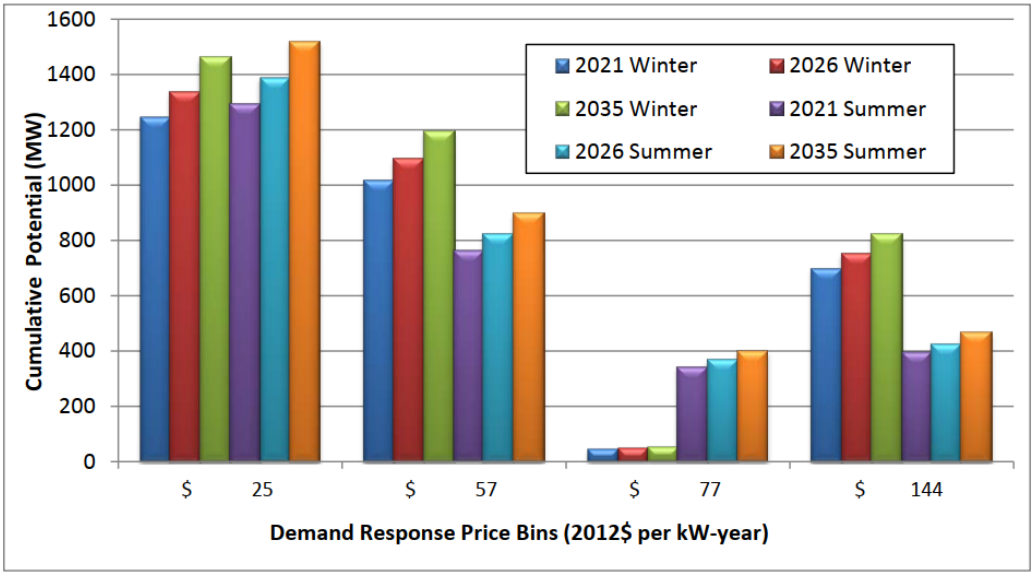
As the Council explained, "When compared to the alternative of constructing a simple cycle gas-fired turbine, demand response can be deployed sooner, in quantities better matched to the peak capacity need, deferring the need for transmission upgrades or expansions." Council 7th Power Plan at 1-10.

The Council summarized their recommendation for demand response as follows: "The Council's analysis indicates that *a minimum of* 600 MW of demand response resources would be cost-effective to develop under all future conditions tested across all scenarios which do not rely on increased firm capacity imports." Council 7th Power Plan at 3-4 (emphasis supplied).

Furthermore, the Council's Plan clearly shows that substantially more demand response would be available at lower cost than other alternatives selected by the DEIS analysis within five years if the region chose to develop it.

For example, as shown in Fig. 3-7 of the 7th Power Plan below, over 2,000 MW of cost-effective demand response is available in the 7th Plan at less than $77/kW-year (2012$), compared to new natural gas power plants at $125/kW-year and above. 7th Plan, Table H-10, Frame Gas Turbine Cost Summary.

Figure 3 - 7: Demand Response Resource Supply Curve



7th Northwest Power Plan at 3-22

Demand response is well suited to Northwest and winter peaking needs and at scale could directly substitute for LSR hydrogeneration ramping and sustained peaking capacity, while gaining additional reliability and economic benefits from reduced transmission losses and congestion, and reducing risk from interannual hydro variability, especially during low or critical water periods when the LSR hydrogeneration operating range will be reduced by 20% or greater.

The DEIS does not include the full range of the demand response resource potential identified by the Council's 7th Plan, and does not provide an explanation for this omission. The failure to use accurate availability and cost for demand response resources means that,, especially for MO3, the DEIS Replacement Power Analysis increases the need for other more expensive resources, particularly battery storage, to address the capacity gap if the LSR hydrogeneration is retired.

4.5 Wind Energy

The Joint Commenters are concerned that Montana wind is not included in the DEIS replacement portfolios, especially for MO3. It is well known that Montana wind is available in vast quantities, with very high capacity factors. And as the DEIS states, Montana wind has a generation profile that is closely aligned with Pacific Northwest area loads. DEIS Appendix H at line 816. Yet the DEIS includes solar plus battery resources in MO3, but not Montana wind. Nor does the DEIS assess wind plus battery storage or pumped storage, a significant possibility in Montana due to the potential availability of the Absaroka Gordon Butte project, a proposed highly efficient 400 MW project that could be available by 2025. The fragmentary comments on wind analysis in the DEIS make it difficult to discern the reason for this result. One possibility is that when solar PV was picked for the MO3 alternative, and then battery storage resources were added to provide winter flexibility, this sequence precluded the full consideration of Montana wind. Again in this instance, the DEIS energy analysis fails to provide sufficient information about the resource portfolio assessment, and a comprehensive IRP analysis may well have resulted in the inclusion of significant quantities of Montana wind.

4.6 Renewable Energy and Storage Capacity and Flexibility Value

The DEIS Replacement Portfolio Analysis takes a limited view of renewable energy and storage resource capabilities, and misrepresents the capabilities of hydrogeneration. The DEIS states:

> Solar, however, does not produce energy during the night. Wind, however, can produce energy during both the daytime and nighttime hours. Together, these resources would allow for generation day and night, mitigating the lost firm energy production of the lower Snake River projects. Utility-scale batteries would replace the lost flexibility and ramping capability of the lower Snake River projects. However, the batteries provide an imperfect replacement for the lost capability of the lower Snake River projects because, while batteries can be discharged to provide energy, they also need to be recharged and consume energy on a net basis.
>
> *DEIS Chapter 3 at line 27404*

While it is appropriate and necessary to measure the net contribution any particular resource makes to system value, no resource stands alone. Wind, solar and battery resources will be operated in conjunction with CRS hydrogeneration and other resources. One of the important missing pieces of the DEIS analysis is full consideration of how CRS hydrogeneration and new renewable, storage and demand response resources can be operated in coordinated and complementary fashion, increasing overall system value. For MO3, the DEIS did not assess system flexibility following LSR dam breach and hydrogeneration retirement and optimize the resource portfolio accordingly. For example, an optimized mix of advanced energy efficiency, demand response, storage, and renewable generation diversity could enhance the ability of the remaining CRS hydrogeneration to provide flexibility.

Concerning resource diversity, considerable research has shown that diversifying the system portfolio by resource type, performance and geographic diversity will add significant value. For example, the comprehensive Western Wind and Solar Integration Study found that increasing the size of the geographic area over which wind and solar resources are drawn substantially reduces variability.[13]

The claim that energy storage such as batteries are an "imperfect replacement" is incomplete and misleading. Hydropower is indeed a form of renewable energy, subject to variable energy input from climate and weather patterns just as wind and solar are. Hydropower also inherently combines energy storage and energy generation capability, the same as hybrid wind or solar plus battery storage systems. It is possible that an optimized combination of clean energy resources could provide more system flexibility year-round. Again, because the DEIS did not conduct an IRP analysis, this opportunity was not explored, and particularly for MO3, the analysis is incomplete and inaccurate.

4.7 Battery Storage

The DEIS Replacement Portfolio Analysis considerably underestimates the potential size and capabilities of battery storage. The DEIS states:

> To provide a similar level of sustained ramping (Table 3-160, above) as the lower Snake River projects, 2,265 MW of batteries would be needed. Additionally, the lower Snake River projects provide 250 MW of operating reserves. This would bring the total to 2,515 MW of batteries needed to replicate the peaking and flexibility of the lower Snake River projects. Developing utility-scale batteries of this size is untested. The largest battery facility in the world is currently 100 MW.
>
> *DEIS Chapter 3 at 27427*

This statement is incomplete and misleading. Large grid battery storage projects with contract commitments that are expected be completed by the end of 2021. Major utilities and producers are scaling up battery storage globally.[14] In California alone these include Strata Oxnard (100 MW/400 MWh, online data December 2020), AES Alamitos (100 MW/400 MWh, 2021), Tesla Moss Landing

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[13] See National Renewable Energy Laboratory, Western Wind and Solar Integration Study, https://www.nrel.gov/grid/wwsis.html

[14] GreenTech Media, The Biggest Batteries Coming Soon to a Grid Near You, September 3, 2019, https://www.greentechmedia.com/articles/read/the-biggest-batteries-coming-soon-to-a-grid-near-you

(182.5 MW/730 MWh, December 2020) and Vistra Moss Landing (300 MW/1,200 MWh, December 2020). And notably, the FPL Manatee Energy Storage Center will combine an existing solar project and a new 409 MW/900 MWh battery storage facility in Florida by late 2021.

In Oregon, new storage development[15] includes:

- The 2019 acquisition by Portland General Electric of a part of the Wheatridge three-way hybrid project developed by NextEra Energy Resources LLC, including 300 MW of wind, 50 MW of solar and 30 MW of battery storage starting in December 2021.
- Obsidian Renewables LLC has broken ground for the planned 400-MW Obsidian Solar Center in Lake County with a potential 50-MW flow battery storage system.
- The Avangrid Bakeoven Solar Project in Wasco County, under review by the Oregon Energy Facility Siting Council, would combine 100 MW of lithium-ion or flow batteries and 303 MW of solar generation with construction starting in 2020.
- Ecoplexus is pursuing the proposed 63-MW Madras Solar Energy Facility in Jefferson County, with up to 240 MWh of energy storage.

Much of the capacity for these projects is already in the Bonneville transmission interconnection queue since it will require federal transmission to wheel power to offtakers. The DEIS does not accurately represent the current capability of battery storage resources.

4.8 Inverter-Based Resources

The DEIS Replacement Power Analysis completely sets aside the value of essential reliability services from inverter-based resources, for example, solar, wind and battery storage. The DEIS states:

> Another limitation of the wind, solar, and battery portfolio is its inability to provide voltage and inertia benefits. As described above, the lower Snake River projects provide voltage and inertia benefits to the transmission system. Currently, wind, solar, and batteries do not provide the same level of voltage support as an installed generator, though this may change with advancements in technology. Providing inertia benefits from solar and wind resources and battery technology, however, would be more challenging because these facilities do not have the same heavy rotating mass as hydro

[15] S&P Global, "Kicking coal, Oregon emerges as a solar and energy storage development hub," March 6, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/kicking-coal-oregon-emerges-as-a-solar-and-energy-storage-development-hub-57104313

> generators. New technologies that would allow wind, solar, and batteries to mimic the inertia characteristics of synchronous generators have yet to be developed.
>
> *DEIS Chapter 3 at line 27439*

The technical and field test evidence is totally contrary to this statement. According to the North American Electric Reliability Council (NERC) Essential Reliability Services Working Group (ERSWG), these services are broadly grouped together as frequency support, voltage support and ramping and balancing.[16]

Inverter-based resources have inherent advantages over conventional resources using "spinning mass," including coal, nuclear, gas and hydro. While hydrogeneration is clearly superior to thermal generation in terms of ramp rates, minimum power levels (Pmin), emissions and other attributes, inverter-based resources rely on power electronics and can be much faster and more faithful to a control signal for fast frequency response, voltage support, ramping and other essential reliability services.[17]

Two recent major field studies have validated these findings. In the first study, CAISO, NREL and FirstSolar conducted a rigorous field test of a 300 MW solar facility in Arizona. The results showed that solar projects can reliably provide frequency control, voltage control and ramping capability at scale, with much better response time and fidelity than conventional resources.[18] In the second study, CAISO, Avangrid Renewables, NREL and General Electric conducted tests at a 131 MW wind facility near San Diego, also finding the wind plant performed as well as or better than conventional units.[19]

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[16] NERC, "Essential Reliability Services Whitepaper on Sufficiency Guidelines," December 2016, https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf

[17] Michael Milligan, "Sources of grid reliability services," Electricity Journal, 2018, https://doi.org/10.1016/j.tej.2018.10.002

[18] Utility Dive, "California solar pilot shows how renewables can provide grid services," October 16, 2017, https://www.utilitydive.com/news/california-solar-pilot-shows-how-renewables-can-provide-grid-services/506762/ Also see Clyde Loutan et al., Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant https://www.nrel.gov/docs/fy17osti/67799.pdf

[19] Utility Dive, "Wind plants can provide grid services similar to gas, hydro, easing renewables integration: CAISO," March 13, 2020, https://www.utilitydive.com/news/wind-plants-can-provide-grid-services-similar-to-gas-hydro-easing-renewab/574070/ Also see California ISO, Avangrid Renewables and NREL, "Avangrid Renewables Tule Wind Farm: Demonstration of Capability to Provide Essential Grid Services, March 2020, http://www.caiso.com/Documents/WindPowerPlantTestResults.pdf

To be sure, much work remains to provide full system integration and compensation to enable the capabilities of inverter-based resources. However, as the electric power system expands and requires additional reliability and resilience, the superior performance of inverter-based resources will surely mean an important and growing role for wind, solar and battery systems in providing essential reliability services. By focusing its analysis on 2022 as a replacement date, the DEIS arbitrarily avoids addressing any of these developments and their potential role in replacing the power from the Lower Snake River dams.

The DEIS does not explain why, in the face of abundant engineering analysis and field testing, it rejected consideration of these capabilities. This failure means it is likely the Replacement Power Analysis assumes additional resources at greater cost than necessary over time – especially inflating the overall costs of MO3.

4.9 Pumped Storage

While the DEIS Replacement Power Analysis provides a short description of the pumped hydro resource, it does not further review directly relevant developments in the Northwest. There are at least three pumped storage projects that could be constructed in the region by the mid to late 2020s, Swan Lake (Klamath County, Oregon), Goldendale (Klickitat County, Washington), and the Absaroka Gordon Butte project (Meagher County, Montana). Each could provide significant support and increase the capacity and flexibility of the CRS. The DEIS only discusses the prospective cost of pumped storage, and does not discuss whether these important resource characteristics were considered.

4.10 Future Market Value

Over the last decade, power markets in the Western Interconnection have started undergoing a profound change on both the supply and demand side. These changes have already substantially affected the operation and net revenues of the CRS. The DEIS Replacement Power Analysis does not consider these factors with regard to the alternatives, particularly MO3.

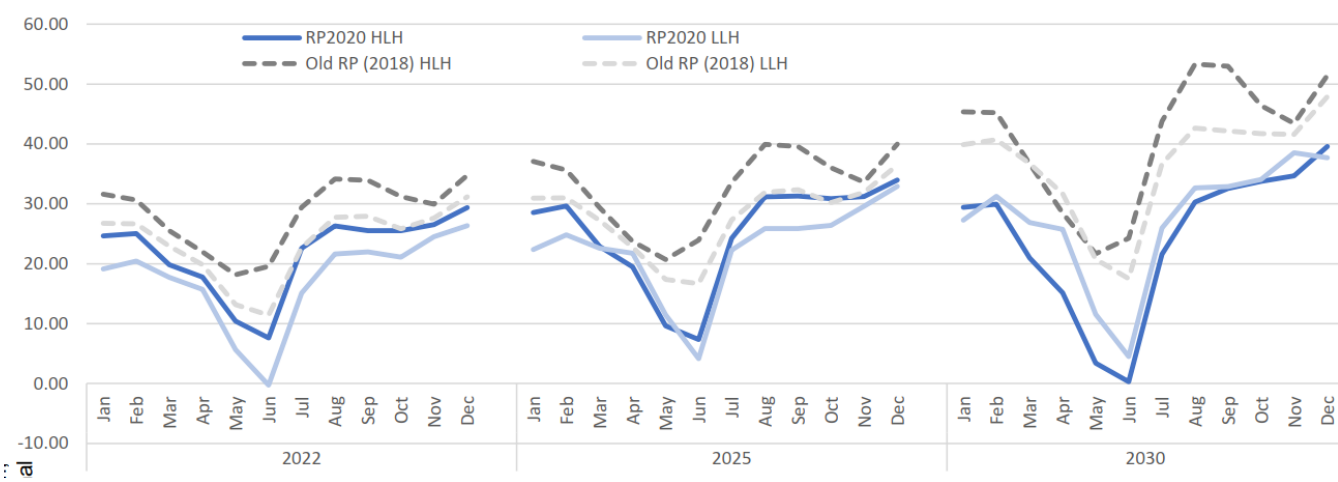
The first key factor is the persistently low natural gas commodity prices since 2010, when shale gas became a dominant factor in the North American market. The price of gas has varied between about

$2.50 and $4.00/mmBtu over the last decade, well below the higher prices for most of the previous decade. Natural gas power plants generally set the marginal price in western power markets, though the price may vary in different markets and trading hubs. Even in the Northwest, gas sets the price for power products at the Mid-C market hub most of the year, except during the spring runoff, when hydrogeneration peaks, and most thermal generation goes offline for annual maintenance.

In California, the advent of substantial solar resources has led to the widely recognized "duck curve." During the middle of the day, solar energy, which has very little variable cost, displaces natural gas and other competing resources. The less efficient gas plants reduce output or go offline until the late afternoon ramp when overall demand rises toward early evening peak. In the years since 2014, this effect has become more and more pronounced. However, while mid-day California market prices are much lower than a decade ago, evening peak prices are much higher. Overall, total annual revenue in the California market, and to a great degree at Mid-C, is still correlated to natural gas prices.

The Bonneville Power Administration has been at a disadvantage selling its secondary energy from the CRS into the Mid-C and California markets. As the price of commodity natural gas has declined and market prices have fallen accordingly, BPA secondary revenues have declined, causing significant rate pressure on its wholesale firm power rates and the bills paid by its preference utility consumers.

As a recent presentation on the draft BPA 2020 Resource Program Update indicated, these trends are likely to continue, especially as renewable energy that is cheaper than natural gas begins to set market prices in California and throughout the west in a greater percentage of hours across the year.



As the chart above[20] illustrates, the Mid-C High Load Hour product (heavy blue trace) is projected to decline substantially over this decade, partly because of continued decline in gas prices and partly from the increase in less expensive renewable energy.

As the secular trend in both the Northwest and California power markets goes downward, CRS secondary energy sales revenue will decline. But because of the need for system flexibility, both in the morning and late afternoon ramp periods, the value proposition of the non-firm power capabilities of the CRS will shift from bulk secondary energy to flexibility, capacity and ramping products.

Because LSR dams are primarily run-of-river facilities, their hydrogeneration is less flexible than the mainstem Columbia CRS projects, and the relative value of the LSR hydrogeneration flexibility as well as energy will decline going forward. But because the DEIS Replacement Power Analysis only considers conditions in the study year of 2022, these effects are not adequately captured, leading to an arbitrary overvaluation of the LSR hydrogeneration in the DEIS.

4.11 Interregional Imports

The DEIS Replacement Power Analysis does not consider increasing interregional power imports from California and other areas in the Western Interconnection for the replacement portfolios, especially MO3. The Northwest power market, particularly at the Mid-C trading hub, has followed the California market more closely in recent years, with the exception of the spring runoff period in the Northwest. That is because the Pacific Intertie allows for substantial trading between the two regions.

In the near future, significant amounts of California surplus power will flow from the low-priced CAISO market to the Northwest when system conditions price the Mid-C market at a higher level. Thus, both markets will converge and, on average, decline in price.

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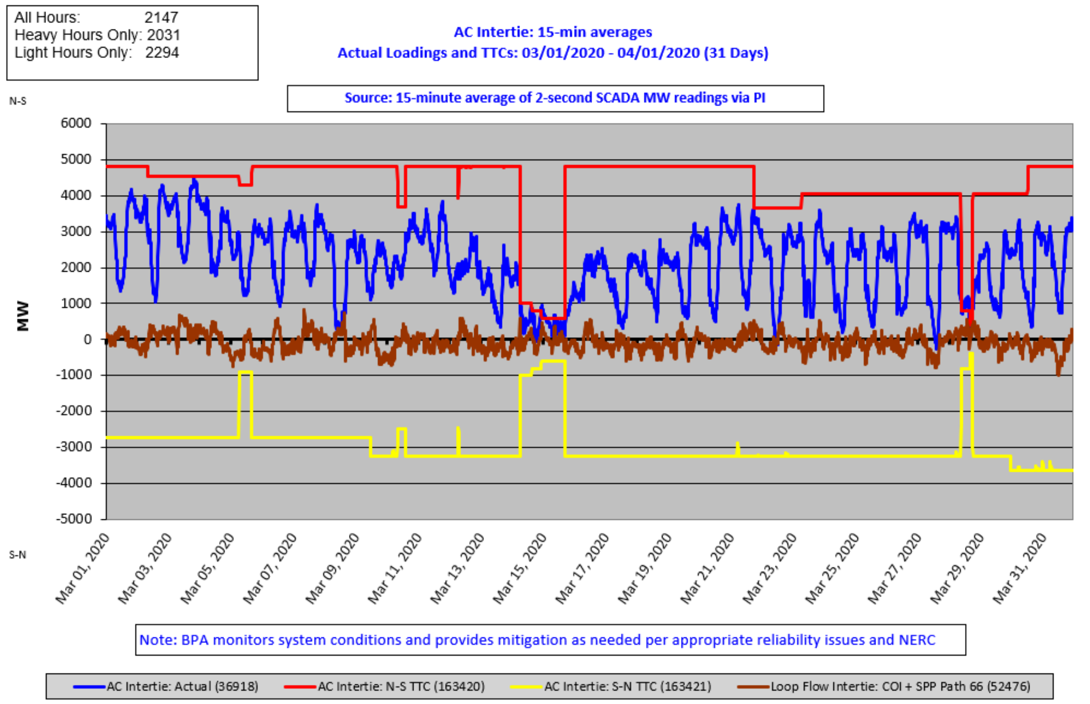
[20] Bonneville Power Administration, 2020 Resource Program Update, March 17, 2020, https://www.bpa.gov/Finance/RateCases/BP-22-Rate-Case/Documents/Combined%20PPT%20for%20workshop%203.17.pdf



The chart above[21] illustrates these ongoing developments. It shows net power exports from the Northwest to California in March 2020 on the AC Intertie. The red trace shows North-South transfer capacity and the yellow trace shows South-North capacity, which vary when there are outages or planned maintenance on the AC Intertie system. The blue trace shows net exports. Over the last year, net imports to the Northwest – where the blue line goes below zero, have been occurring more frequently than in the past.

In the month of March, when the Northwest snowpack is beginning to melt and winter demand peaks have declined, Mid-C prices are generally lower than California market prices. As a result, over the last two decades, power almost never flowed from California to the Northwest in March. However, starting in 2019, that has changed, whenever California prices are low enough relative to the Mid-C market.

It now seems clear that imports into the Northwest will continue to grow and costs will decline. There are a number of factors including the continued decline in natural gas prices, increasing solar energy,

[21] https://transmission.bpa.gov/BUSINESS/Operations/Paths/Interties/monthly/AC/2020/AC_2020-03.xls

changes in demand and the interannual variation of hydro in each region. This provides an important opportunity to include interregional imports as a potential replacement resource, especially during the winter. Increased imports would be a particularly good choice for mid-winter replacement of LSR hydrogeneration. However, the DEIS Replacement Power Analysis does not address this possibility nor explain why it did not do so. Again, this likely inflates the costs of the MO3 alternative.

4.12 Power Market Structure

Because the Replacement Power Analysis only included the study year of 2022, it did not consider the profound changes in power market structure in the Northwest and the Western Interconnection. We provide two examples. In March 2022, the Bonneville Power Administration expects to become a participant in the Western Energy Imbalance Market (EIM), which optimizes generation dispatch and use of reserves within each hour across most of the Western Interconnection. On Sept. 26, 2019, BPA signed an implementation agreement with the California Independent System Operator and a record of decision in a move toward joining the EIM in 2022.[22]

In addition, after becoming an EIM Entity, Bonneville will be eligible to join the proposed Enhanced Day Ahead Market extension to the EIM, enabling it to change CRS operations to reduce operating costs and risks and increase revenues for both firm power and secondary sales. While the eventual fruition of the EDAM is not certain, the growing consensus through the Western Interconnection is that market expansion offers substantial reliability, economic and environmental benefits.

Bonneville engaged in two substantial studies including a full net benefits study to assess the relative value of joining the EIM. The EIM Record of Decision indicates that net benefits could fall in the range of $29 to $34 million per year.[23] The anticipated benefits of the EDAM are expected to be much larger, and if it commences operation in the coming years, the existing Mid-C market and other trading hubs in the Western Interconnection will diminish in participation, reducing market depth, stability and efficient price discovery.

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[22] Bonneville Power Administration, Energy Imbalance Market, https://www.bpa.gov/Projects/Initiatives/EIM/Pages/Energy-Imbalance-Market.aspx

[23] Administrator's Record of Decision, Energy Imbalance Market Policy, September 2019, at 112, https://www.bpa.gov/news/pubs/RecordsofDecision/rod-20190926-Energy-Imbalance-Market-Policy.pdf

Yet because the Replacement Power Analysis only included the study year of 2022, no analysis was conducted to examine the potential benefits and challenges of CRS participation in the changing power market structure, even though ample information to do so was available and the effects of this interconnection process are highly relevant to assessing the feasibility and costs of implementing MO3. The DEIS does not discuss the EIM and EDAM, and does not explain this omission.

4.13 Transmission Resources and Operations

Because the Replacement Power Analysis only included the study year of 2022, it did not consider potential transmission expansion, grid modernization and more efficient operations. Among other elements directly relevant to the CRS, this includes the ongoing efforts by BPA to revise its open access transmission tariff, reshape its transmission products for the emerging needs of more diverse and flexible resources, engage in a major grid modernization program supporting its participation in the EIM and other system optimization purposes, and potentially add new transmission lines and supporting resources.

One major example is the possible Montana-to-Washington transmission expansion, which would add 600 MW of transfer capacity in the federal transmission system between western Montana and eastern Washington. An earlier environmental review of the projected was halted in 2013 when Bonneville determined that commercial offtaker potential had dwindled. Now, as a result of the review of the Montana Renewable Development Action Plan in 2018, co-sponsored by Bonneville and the Governor of Montana, and with further state energy policy developments and cost reductions favoring expanded transmission capacity to carry Montana wind to load in northern Idaho, Washington and Oregon, the prospects of M2W are improving. An even larger new transmission project known as Garrison-to-Ashe is also on the drawing boards, with a prospective completion date of 2030.

Federal transmission expansion, grid modernization, tariff reform and more efficient transmission system operations will improve the value of renewable energy resources that could replace LSR hydrogeneration. But the DEIS fails to address these opportunities.

4.14 Columbia River Treaty

The DEIS has been conducted in parallel with ongoing negotiations between the US and Canada over the future of the Columbia River Treaty, with two of the co-lead agencies, the Bonneville Power Administration and US Army Corps of Engineers jointly constituting the US Entity. Certain provisions of the Treaty expire in 2024. The DEIS states:

> The 2016 CRT-related operations, were applied in the EIS analysis, as the best-available information. If CRT-related operations change in a manner that presents new information or circumstances resulting in significant changes that were not previously addressed, those changes will be addressed by this NEPA process if they are identified in time or subsequently in another NEPA process, if necessary.
>
> *DEIS Chapter 2 at 2326*

Because the Columbia River Treaty drives CRS planning and operations in a foundational way, it should have been analyzed in the Replacement Power Analysis, but was not due to the limitation of the analysis only to the study year of 2022.

4.15 Inappropriate and Incomplete "Coal Sensitivity"

In a complete diversion from the trend of not considering anything outside of the 2022 study year, the DEIS conducts a self-styled "coal sensitivity" considering the impact on regional energy, capacity and resource adequacy if additional coal generation serving the Pacific Northwest is retired beyond announced retirements as of the Replacement Power Analysis in 2022. With regard to MO3, the DEIS states:

> In the future condition with additional coal-plant retirements, this option would not be sufficient to return the LOLP to the No Action level, because without coal, more of the capability or replacement capability of the Lower Snake River (LSR) projects would be needed for power system reliability.
>
> *DEIS Appendix H at line 653*

This sensitivity is built upon completely erroneous assumptions and completely disregards the likelihood that the relatively inflexible and risky coal resource can be replaced with a more diverse, reliable, less polluting and less costly portfolio that affords additional flexibility to the CRS and improves Northwest power system performance.

Noting the ongoing development of public policy promoting a transition from fossil fuel generation to clean energy resources, the DEIS further states:

> In light of this legislative and policy trend, the co-lead agencies assume that no new gas-fired generation would be built to replace the lost generation from the lower Snake River dams, only zero-carbon resources may be selected. At the utility-scale, the current best options are solar and wind resources, some batteries, and demand response programs. For MO3, the EIS analysis identified a potential zero-carbon replacement portfolio consisting of 2,550 MW of solar resources, , and 600 MW of demand response to restore LOLP. Tis portfolio relies on using the existing regional system to help make up for some of the lost capabilities of the lower Snake River projects - primarily by operating thermal plants more frequently to meet regional load. However, in light of regional policy initiatives to curtail or cease the operation of thermal plants, a zero-carbon resource replacement portfolio with insufficient dispatchable sustained capacity may not be feasible. If the replacement does not include firm generating capacity with only 600 MW of dispatchable capability, it is likely not a realistic assumption for MO3 where a substantial amount of generation capacity is lost.
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> *DEIS Chapter 7 at line 386*

The Joint Commenters agree that new gas-fired generation should not be built to replace LSR hydrogeneration. But we strongly disagree that regional clean energy policy undermines the feasibility of replacing LSR hydrogeneration with a clean energy portfolio. Indeed, as explained at length in these comments, the DEIS does not provide a valid test of that assertion. Furthermore, the manifest goal of Northwest clean energy policy is to expand the capability of those resources to replace thermal generation in a reliable, clean and affordable manner. The success already accomplished under these policies is a matter of record. Here we cite two examples.

The respective utilities with requirements under the 2006 Washington Energy Independence Act have met their responsibilities to acquire all cost-effective energy efficiency and to achieve the targets under the Act's Renewable Portfolio Standards, and often exceeded them.[24] And in Oregon, SB 1547, the "coal-to-clean" legislation passed in 2016, sets a new Renewable Portfolio Standard of 50% by 2040 and requires utilities to cease using coal-fired power no later than 2025. All three of Oregon's investor

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[24] NW Energy Coalition, "I-937: The only thing we had to fear was fear itself: The first in a series celebrating the passage of Initiative 937 and its many benefits for Washington," September 27, 2016, https://nwenergy.org/uncategorized/i-937-the-only-thing-we-had-to-fear-was-fear-itself/

owned utilities, Portland General Electric, PacifiCorp and Idaho Power, have responded by accelerating coal retirement plans and committing to major clean energy acquisitions. Those clean energy actions replicated throughout the region by coal-owning utilities will rapidly reduce the apparent "resource adequacy gap" resulting from coal retirement. The Joint Commenters fully anticipate this will result in reduced energy costs, major reductions in greenhouse gas emissions, and improved environmental performance.

Turning to the DEIS "coal sensitivity" analysis itself, as noted in the DEIS, announced coal retirements as of 2022 are already included in the energy assessment. Yet the DEIS forges on to assess how further retirements of part or all of the remaining coal fleet could affect the CRS *as if* they occurred in 2022. The DEIS states:

> While the scope of the CRSO EIS analysis is not necessarily to address resource adequacy issues related to the No Action Alternative because the coal-plant retirements are not serving Federal load, resource acquisitions made by the region for the coal-plant retirements will affect how changes in CRS hydropower would impact the region.
>
> *DEIS Chapter 3 at line 25385*

Yet no one would argue that all regional coal could be, or even should be retired in 2022, despite the reduction in climate change that might entail. Retiring the entire coal fleet, with its far greater contribution to the Northwest power system than LSR hydrogeneration, will require a careful and measured effort to phase out those resources and replace them with a clean energy portfolio. As discussed above, state policy and utility IRP processes under way in the region are fully taking up that task. The DEIS ignores these processes and instead makes unfounded assertions.

In particular, the coal retirement sensitivity appears to build linkages between MO3 and coal-plant retirements that do not exist. In reality, coal units in the West are used to meet capacity needs of their owners. No preference customer of the Bonneville Power Administration is an owner of a share of any existing coal generation. The preference customers and Bonneville itself have no legal obligation whatsoever for the future course of such coal plants, nor for resource replacement as they are retired. Rather coal plant retirement decisions that ensure reliable, affordable energy services are the responsibility of the owners and the respective state utility commissions that regulate them. At the date of submission of these comments, Portland General Electric (PGE) is pursuing a comprehensive strategy to replace the energy and capacity services of its Boardman coal plant in Oregon and its share of the Colstrip coal plant in Montana, as well as other system changes. In 2019, PGE and the Bonneville Power Administration executed two contracts for 100 MW of power services for five years. This contract, executed before filing of the DEIS, does not appear to be included in the coal sensitivity analysis. PGE is also currently seeking consideration of acknowledgement by the Oregon Public Utility Commission (OPUC) of its 2019 Integrated Resource Plan, including up to 150 aMW of renewable energy resources and up to 690 MW of capacity resources.

PacifiCorp is addressing coal retirement and replacement in its 2019 IRP, and is also seeking acknowledgement from the OPUC and approval by other regulatory commissions in its six-state service area targeting almost 2,400 aMW of new solar resources collocated with about 600 MW of battery storage as well as almost 2,000 MW of new wind resource by the end of 2023, and construction of a new high-capacity transmission line by 2024 in order to transfer additional wind resources to replace coal, to improve reliability and address other system needs.

Other investor owned utilities that own coal generation resources in the Northwest that are retiring or may retire within this decade are also considering replacement portfolios. None of these replacement plans are considered in the DEIS "coal sensitivity".

The assumption that nothing will be done until coal generation actually retires is false. The DEIS does not assess that state utility commissions will mandate that utility coal-owners develop fully optimized and least-cost resource portfolios as part of the approval process to replace the coal resources, thus maintaining overall operational reliability and resource adequacy on their systems and assuring continuity of operation for the Northwest power system as a whole. Indeed, the DEIS does not reference the comprehensive and detailed IRP analyses being conducted to address exactly this question by every utility owning coal resources in the Northwest and the Western Interconnection. Nor does the DEIS explain why this information was not studied.

Furthermore, increased coal retirements in the West will change the landscape of operational reliability and resource adequacy. The new resource portfolios being developed by PGE, PacifiCorp and others are more diverse by resource type, performance and geography than has ever been the case in the past. They rely strongly on fast-response generation, demand side and storage resources, all with inverter-based grid interconnections that can respond much faster and more precisely to a control signal that coal generation. They do not require minimum run rates that require uneconomic operation during periods of low system demand. They do not produce the wide array of environmental pollutants and greenhouse gases of coal generation. They do not depend on volatile fuel markets. The replacement portfolios will not only be cheaper than continuing operation of most of the Northwest coal fleet, they will also provide improved reliability and resource adequacy. None of these factors, well developed in technical literature and demonstrated in the IRPs referred to here, are reflected in the DEIS energy analysis.

The timing of coal generation retirements and the nature of potential replacement resources will have an effect on CRS operations, given that the Western Interconnection is a synchronous system under federal mandatory reliability standards for frequency regulation and other compliance requirements. Under the NERC transmission planning (TPL) mandatory reliability standards, studying these factors is a legal requirement for the BPA transmission system, and studies must be conducted for time frames out to 10 years. However, no such analysis was undertaken for the DEIS energy analysis.

Indeed, the related transmission studies in Step 4 of the DEIS energy analysis framework have deficiencies of their own. The transmission reliability analysis (Appendix H, page H-3-14) was only performed for the base case for a 2023 study year using WECC powerflow cases. Oddly, the DEIS used a summer WECC case but performed a peak load analysis where it assumed minimum hydro output. Yet the DEIS transmission analysis appears not to have made use of the WECC Heavy Winter powerflow case. In any event, there was no explanation nor any demonstration of analytical results to justify this choice.

In summary, the DEIS "coal sensitivity" completely ignores the policy, planning and resource acquisition steps that are being taken to retire coal and gain immense economic, climate, environmental and reliability gains. The DEIS justifies its inadequate and misleading analysis with vague references to impacts on the CRS, but provides very little analysis or evidence, especially on transmission impacts. The DEIS does not explain why it did not conduct the long-term IRP analysis that would be required to assess potential impacts of coal retirement on the CRS and the resource portfolios for the DEIS alternatives.

4.16 "Conventional Least-Cost Portfolio"

The Replacement Power Analysis refers to the all-gas replacement scenario for MO3 as a "least cost" portfolio. However, an IRP analysis would not determine that a specific resource is "least cost" by assessing only one attribute, such as contribution to resource adequacy. "Least cost" resources are identified through replacement portfolio optimization, which was not accomplished in the DEIS. The blanket assumption that the specific type of natural gas generation chosen for the "least-cost conventional" portfolio is without technical merit and is inconsistent with economic conclusions from almost every recent Western Interconnection IRP process, which favor mixes of renewables, gas, energy storage and demand side resources.

4.17 Substantial Costs for Necessary LSR Powerhouse Upgrades Not Considered

The Lower Snake River hydro generation facilities commenced commercial operation between 1962 and 1975. Since these facilities are assumed to have an engineering and economic life of 50 years, the risk of unforced outage and longer shutdown for extended maintenance, and even forced retirement, continues to grow as the 50-year anniversary approaches.

The common language metaphor for this process is the "bathtub curve" [25] – high maintenance costs when a facility is first put into place, followed by a long period of reliable and low-cost operation, and then increasing costs as parts begin to weaken and fail, followed either by refurbishment, replacement or retirement. The bathtub curve is a useful way to conceptualize the future of the LSR hydrogeneration facilities.

Of the 24 generation units at the LSR dams, the first three at Ice Harbor dam are now undergoing a refurbishment and replacement program. In a news release in June 2019, the project manager stated, "After 50 years of operation and increasing maintenance requirements, the need to replace the existing turbine runners at Ice Harbor presented the opportunity to pursue new turbine runner designs with fish passage improvement as a priority."[26] The project cost is currently estimated at $92 million. The first

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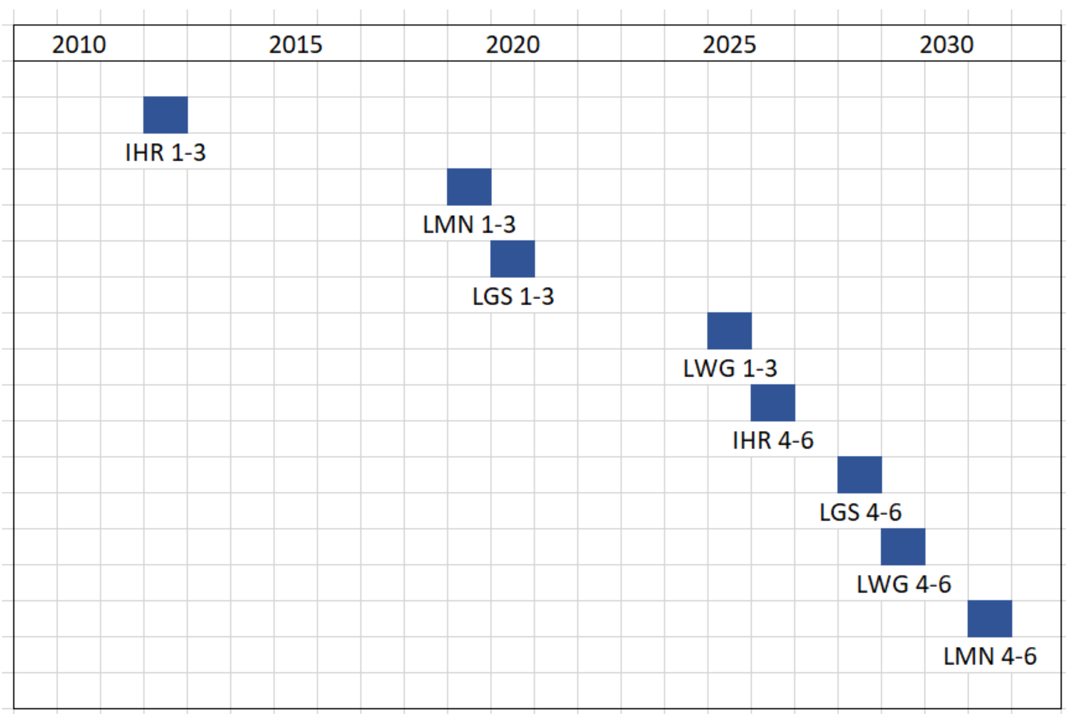
[25] Sumereder, C. (2008). Statistical lifetime of hydro generators and failure analysis. IEEE Transactions on Dielectrics and Electrical Insulation, 15(3), 678–685. doi:10.1109/tdei.2008.4543104

[26] US Army Corps of Engineers Walla Walla District, "New high-tech turbines at Ice Harbor improve safety for fish, produce more power." https://www.nww.usace.army.mil/Media/News-Releases/Article/1866445/19-067-new-high-tech-turbines-at-ice-harbor-improve-safety-for-fish-produce-mor/

new turbine was placed in service in May 2019, about 57 years after the original equipment began commercial operation. If CRS operations continue in accordance with the DEIS Preferred Alternative, similar upgrade and replacements will be required at the other 21 LSR generating units starting in this decade. If the MO3 is adopted, these costs will be avoided.

The first three generating units at Ice Harbor commenced operation in 1962, the second set of three units in 1976. Likewise, an initial and second set of generators commenced operation at Lower Monumental in 1969 and 1981, at Little Goose in 1970 and 1978, and at Lower Granite in 1975 and 1979, respectively. Thus, the 50th anniversaries for the various turbine groups began in 2012 (Ice Harbor 1-3) and will conclude in 2031 (Lower Monumental 4-6), with a substantial amount of powerhouse facilities reaching that anniversary in the mid to late 2020s.

Lower Snake River Hydro Generation – 50th Anniversary Dates



Data source: US Army Corps of Engineers, Walla Walla Division

It is reasonable to foresee that no later than the mid-2020s, the Army Corps of Engineers and BPA will need to agree on a refurbishment and modernization program for the 21 remaining generation units in the four Lower Snake River dams if the Preferred Alternative or another option other than MO3 is pursued. Indeed, the first set of units at Lower Monumental and Little Goose have already passed the 50th anniversary.

However, the CRSO DEIS steadfastly refuses to directly address this likelihood. Instead, the DEIS states,

> ***Improved Fish Passage Turbines[15]***
>
> This structural measure is include under the NAA, all of the multiple objective alternatives, and the preferred alternative. These costs for this measure are included in the capital costs estimates, as provided in the Strategic Asset Management Plan (2018).
>
> [15] Note that this structural measure is being implemented under the No Action Alternative, and is also included under all of the MO alternatives.
>
> **Cost Estimates of the Structural Measures**
>
> ***No Action Alternative***
>
> The structural measures under the multi-objective alternatives are separate from the ongoing structural measures occurring under the NAA and therefore there are no cost estimates for structural measures under the NAA.

DEIS, Appendix Q, Annex A, Q-A-7 and 8

It appears from this language that the prospect for avoiding the future necessary refurbishment and modernization of the four Lower Snake River dam powerhouses is not considered in the DEIS energy analysis for MO3.

Furthermore, on March 31, 2020, the Bonneville Power Administration issued a message by email that included the following statement:

> Major powertrain replacements for the Snake River Dam hydroelectric assets are not currently forecasted to occur within our 20-year system asset plan. Long-term planning analyses that calculate the optimal economic time to replace equipment based on current and expected equipment health, probability of failure and outage consequence, point to the late 2030s as the earliest replacement dates. In fact, most of the optimal replacement

> dates are spread between the 2040s and 2060s for the Lower Snake dams for turbine and generator replacements.[27]

To the knowledge of the Joint Commenters, this is the first statement made publicly by Bonneville that the LSR powerhouse upgrades can be delayed until the original equipment is 70 to 90 years old.

As previously noted, current work on the first three generation units at Ice Harbor will cost about $92 million under contracts executed several years ago. Similarly, a major modernization project for the powerhouse at McNary dam on the Lower Columbia River is also in progress. The McNary project will cost approximately $340 million to upgrade 980 MW of generation.

Together, the Lower Snake River dams have a combined nameplate capacity of over 3,000 MW, more than three times as much as McNary. While it is not possible to make a direct comparison, it seems likely that a complete Lower Snake River hydrogeneration upgrade could cost well in excess of $1 billion. Whether this occurs starting in the mid to late 2020s, or is mostly accomplished after 2040, the DEIS totally fails to address this crucial element affecting future CRS operations and costs.

5. Conclusion

The Joint Commenters conclude these comments by summarizing the main findings:

1. The DEIS confirms that dam breaching and clean energy power replacement can maintain electric system reliability while providing the best chance for fish restoration.
2. The DEIS fails to meet energy industry resource planning standards, resulting in numerous inaccuracies and an exaggerated cost for clean energy power replacement.
3. Because the DEIS fails to provide the accurate information needed to make informed decisions, a new, more rigorous study is required.

The preceding comments of the Joint Commenters demonstrate conclusively that the DEIS energy analysis failed to meet industry standards and did not achieve optimized, least cost/least risk outcomes for the energy resource portfolios for each of the DEIS alternatives, especially MO3, the dam breach/hydrogeneration retirement alternative. This has resulted in proposed replacement portfolios that are nearly certain to be substandard in performance and excessively high in cost, with

[27] "BPA Finances and Snake Dam hydroelectric information," G. Douglas Johnson, Senior Spokesman, BPA, March 31, 2020.

proportionally excessive costs for wholesale and retail electric rates. These failures directly result in the agencies selecting a preferred alternative without adequate justification.

Thus, the CRSO DEIS fails to accomplish a "hard look" at the energy options to mitigate impact to protected species required by the National Environmental Policy Act and the Endangered Species Act.

The Joint Commenters recommend that the entire energy analysis be redone for the final EIS, employing comprehensive long-term portfolio analysis consistent with standard industry practices.

Respectfully submitted,

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