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STATE OF UTAH

Public Service Commission

In the Matter of PacifiCorp's 2017 Integrated Resource Plan	Docket No. 17-035-16

SIERRA CLUB COMMENTS
[REDACTED]

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1. INTRODUCTION

Sierra Club appreciates the opportunity to comment on PacifiCorp's 2017 Integrated Resource Plan (IRP). These comments were prepared with technical expertise from Dr. Jeremy Fisher and Kenji Takahashi of Synapse Energy Economics. This is the 4th IRP in which Sierra Club has participated as an active stakeholder throughout the public process, and as an active intervenor. We believe that IRPs are important documents: they are the *de facto* explanation for major capital projects, investments, and contracts, they set the tone for how the utility expects to move forward on clean energy procurement, efficiency rollouts, jurisdictional allocations, energy market transformation, and environmental compliance, and in PacifiCorp's jurisdictions, they are key in setting the avoided cost of qualified facilities under PURPA.[1]

An IRP has multiple purposes. In action, it is meant to guide investments, but it is also a key framework for the discussion of strategy, state priorities, utility vulnerabilities, risks, and uncertainty. An IRP is meant to provide a forum for discussion and mutual understanding, the alleviation of risk and the promotion of transparency. And while PacifiCorp has been lauded for having an outwardly comprehensive and public IRP, ultimately, the 2017 IRP appears to be driven by the Company's financial strategy, not data.

The strength of a planning process rests on its assumptions, inputs, and mechanics. Sierra Club's experience, validated through utility commission proceedings across the country, is that utility plans are prone to highly subjective decisions that impact assumptions, inputs, and mechanics.

[1] Public Utility Regulatory Act, 16 U.S.C § 2601 et seq.

These assumptions can be highly transparent – like fuel prices or the costs of new generation technology – or buried deep in a modeling construct – such as limits on new resources, options to retire existing resources, or shadow constraints. The more complex a utility's modeling process becomes, the more difficult it is to create a public forum for discussion and mutual understanding. And when a utility has a strategic – or financial – concern that could be revealed through open and transparent planning, it has an incentive to close or obfuscate the process.

Despite the Company's exhaustive and lengthy stakeholder process, and the provision of workpapers following the IRP submission, PacifiCorp's 2017 IRP is neither transparent nor open. As we show below, the Company has oriented the IRP to specifically exclude some of the most critical questions now facing the utility on the economics of the Company's coal plants, its obligations under the Clean Air Act, the value of new transmission, and its ability to achieve aggressive demand reductions through energy efficiency. With respect to coal unit valuation, key to the Company's near-term decisions and future, Sierra Club has found vastly greater transparency in other coal-dependent states – including Louisiana, Georgia, Kentucky, Indiana, Oklahoma, Idaho, and New Mexico. In each of those states, utilities provided clear valuations of the existing coal fleet and offered regulators and stakeholders the opportunity to engage in a discussion of value, risk, and tradeoffs. PacifiCorp's IRP offers nothing of the kind; instead, kicking the can down the road because of litigation it instigated against EPA and regulatory uncertainty. What the Company does not reveal is that a substantial fraction of its fleet is non-economic today because of the market alone – irrespective of either litigation or regulatory uncertainty. Data from the Company's own modeling (not presented in the IRP) shows that a large fraction of the Company's coal units – not necessarily those facing environmental requirements – are deeply underwater.

Sierra Club's comments focus on five key areas of the 2017 IRP, based on a detailed assessment of PacifiCorp's data, modeling, and assumptions:

1. **Coal economics.** The value and longevity of PacifiCorp's coal fleet is key to every other element of the Company's planning, from its ability to allow renewable energy onto the grid, to the valuation of energy efficiency and distributed generation, to its need for new capacity and new transmission. Sierra Club demonstrates that PacifiCorp's IRP failed the basic function of seeking least-cost, least-risk scenarios including the retirement of non-economic resources.

2. **Regional haze requirements.** PacifiCorp faces finalized Clean Air Act obligations at Hunter 1, Hunter 2, Huntington 1, Huntington 2, Jim Bridger 1, Jim Bridger 2, Dave Johnston 3, Naughton 3, and Wyodak. However, the IRP presumed that EPA (and the public) will simply accept substantially fewer emissions reductions as presented in the Regional Haze Alternatives. Despite the centrality of these alternatives to the Company's planning, PacifiCorp has refused to disclose the basis or logic of the alternatives.

3. **Wind repowering.** PacifiCorp proposes to repower 905 MW of existing wind, increasing the capacity factor of these units. The Company proposes to spend substantial public dollars, accessed via the federal Production Tax Credit, to tear down wind farms less than ten years old with little marginal gain and effectively no incremental ratepayer benefit. Instead, PacifiCorp could, and should, invest in new cost-effective renewable energy projects.

4. **Gateway transmission**. PacifiCorp expects to build a substantial new transmission line in eastern Wyoming to access new wind, finding that the highly cost-effective wind essentially pays for the transmission line. We show that retiring the Dave Johnston coal plant would free up the same transmission at a lower cost to ratepayers.

5. **Demand-side management modeling.** PacifiCorp's modeling of energy efficiency, based on potential studies, assumes that the cost of energy efficiency will steadily increase, and that the Company will be able to access less each year. This finding stands in stark contrast to the actual efficiency gains found year-on-year – at a constant or declining cost. Simply assuming that PacifiCorp can maintain today's savings rate through 2022 would offset 250 MW of incremental capacity, or allow the unreplaced retirement of both Hayden and Craig.

Sierra Club requests that the Commission not acknowledge Action Items 1a (Wind Repowering) and all Action Items 5 (Coal Resource Actions). In addition, we ask that the Commission require PacifiCorp to immediately provide an economic assessment of maintaining Dave Johnston versus building new transmission before acknowledging Action Item 2a (Aeolus to Bridger/Anticline Transmission), and that such analysis be completed in parallel with the CPCN and preapproval process filed in Utah and Wyoming.

2. Economics of Coal Generation

The end goal of an IRP is to generate a least cost plan to meet the needs to consumers in future years. Under Utah Code 54-1-10, the PSC is charged in "engag[ing] in long-range planning… to facilitate the well-planned development and conservation of utility resources." The Commission's IRP rules hone this requirement to pursue **least cost alternatives**:

> The Commission will require PacifiCorp to pursue the least cost alternative for the provision of energy services to its present and future ratepayers that is consistent with safe and reliable service, the fiscal requirements of a financially healthy utility, and the long-run public interest.[2]

While prior to 2011, the Company rejected the evaluation of its existing fleet as part of a least cost planning process, the three subsequent IRPs have recognized that the assessment of the existing coal fleet is a core component of planning, a fact recognized by this Commission in the evaluation of the 2015 IRP:

> …we agree PacifiCorp will need to continue to refine its evaluation of environmental compliance options to determine least cost and least risk approaches… We urge PacifiCorp to give priority in the public process of its 2017 IRP to discuss and weigh alternative approaches for determining

[2] Utah PSC Docket 90-2035-01. Report and Order on Standards and Guidelines. June 18, 1992.

> the least cost path, adjusting for risk and uncertainty, for addressing federal environmental compliance requirements.[3]

Most recently, Chair LeVar, addressing the Public Utilities, Energy, and Technology Interim Committee noted that “the goal of the IRP process is the selection of the optimal set of resources given the expected combination of costs, risks, and uncertainty.”[4] Overall, PacifiCorp is clearly directed to optimize its portfolio around a least cost objective function. And while the Company takes great pains to demonstrate compliance with respect to new resource selection, it completely fails to offer a reasonable – much less least cost – assessment of its existing coal-fired generators. In these comments, we demonstrate that anywhere from a third to a half of PacifiCorp’s coal-fired generators are non-economic today, and would be eliminated from a least cost, or optimized, portfolio. The fact that these plants were not selected for retirement is not a function of their cost effectiveness, it is a choice by PacifiCorp.

PacifiCorp’s handling of its coal-fired generators is undoubtedly the single most important aspect of the Company’s long-term planning. Coal makes up approximately one half of the Company’s firm capacity, almost two-thirds of the Company’s anticipated generation in 2017, and over 90% of its carbon emissions. The presence or absence of individual coal units has a tremendous impact on PacifiCorp’s long-term resource needs and commitments; the Company’s ability to integrate renewable energy; and the availability of transmission, among other long-term planning considerations. Yet, despite these disproportionate impacts on the system and long-term

[3] Docket 15-035-04. Rocky Mountain Power’s 2015 Integrated Resource Plan. Report and Order. Page 16.
[4] Presentation by Chair LeVar, Utah PSC to Public Utilities, Energy, and Technology Interim Committee. May 17, 2017. Available online at https://le.utah.gov/interim/2017/pdf/00002304.pdf

planning, PacifiCorp's 2015 and now 2017 IRPs completely failed to assess the costs and benefits of maintaining the Company's coal-fired generators.

Sierra Club's assessment of the Company's coal fleet, based exclusively on information obtained from the IRP, shows that 2,300 MW – or more than 40% – of PacifiCorp's coal units are non-economic on a going forward basis – even without meeting required environmental compliance obligations. Our analysis shows short-term losses of $86 million (2016$) across twelve coal-fired units, and long-term losses in excess of $430 million (2016$ NPV 2016-2036) across nine coal-fired units owned or co-owned by PacifiCorp.[5]

Why aren't these losses illustrated in PacifiCorp's IRP? It appears because, despite repeated and ongoing requests from multiple stakeholders going back years, PacifiCorp continues to withhold the necessary tools and data to assess these losses either on an individual unit basis or in aggregate. The 2017 IRP is specifically designed to hinder the valuation of PacifiCorp's coal fleet, a strategy employed by the Company in the 2015 IRP cycle.

PacifiCorp is unique in its resistance to demonstrating ratepayer benefits – or losses – from the continued operation of its coal plants. For a decade, Sierra Club, along with its experts, has been engaged in resource planning and valuation dockets across the country, including nearly every vertically integrated state in the country. In PacifiCorp's territory, Sierra Club has been an active participant in long-term planning since 2009, appearing at PacifiCorp's public input meetings and technical conferences, filing comments, and conducting in-depth analysis in ten unique

[5] These are PacifiCorp units Cholla 4, Craig 1, Craig 2, Hayden 1, Hayden 2, Jim Bridger 3, Jim Bridger 4, Naughton 1, and Naughton 2.

PacifiCorp dockets in Utah, Wyoming, Oregon, Washington, and California. PacifiCorp was first asked to assess the viability of its coal fleet in 2009, and since that time PacifiCorp has, uniquely amongst large publicly-owned utilities, shown remarkable resistance to conducting economic analyses of its entire coal fleet as part of regular resource planning.

These concerns are not new. In the 2011 IRP, PacifiCorp presented a shallow analysis of its existing coal units called the "Coal Utilization Study," triggering concerns from multiple parties, including Sierra Club. Sierra Club stated in its comments to PacifiCorp on the Draft 2011 IRP that:

> **The Company should completely model coal plant utilization options, including retirement, for the purposes of determining a least cost solution for ratepayers.** The determination of the most economically efficient choice requires a comprehensive and detailed assessment of the costs associated with a variety of options; limiting the scope of these options imposes a bias on the results, and may result in an unfair burden on consumers.[6]

Oregon's Commission emphasized these concerns in its acknowledgement order:

> Staff, CUB, ODOE, the Sierra Club, RNP, and NWEC criticized the lack of a comprehensive analysis of the costs to upgrade PacifiCorp's coal plants for environmental compliance compared to the costs to retire the coal plants and invest in other resources. These parties emphasized the financial risks associated with investing in aging coal plants and the uncertainties about the scope of potential environmental regulations. Although PacifiCorp filed a Supplemental Coal Replacement Study, Staff and parties continued to have concerns about the sufficiency of the analysis supporting the conclusion that the continued operation of the company's coal fleet, with planned incremental investments, contributes to

[6] Sierra Club comments before the Utah PSC. March 24, 2011. "Comments on Draft 2011 Integrated Resource Plan." Emphasis in original.

> a resource strategy with the best combination of cost and risk for the utility and its customers.[7]

Responding to Commission Staff concerns, PacifiCorp added an action item to the 2011 IRP offering a technical workshop and Coal Replacement Study, stating at the time that "at the technical workshop, the Company [would] present the methodology, assumptions and results of a Coal Replacement Study screening analysis performed for Jim Bridger 3, Jim Bridger 4, Hunter 1 at a minimum. The Company will complete the analysis on as many other units as possible within the time constraints."[8] The resulting Coal Replacement Study in the 2011 IRP Update provided reason for concern, indicating that under a reasonable range of gas and CO_2 prices, much of PacifiCorp's coal fleet could be rendered non-economic.[9] Concluding that March 2012 exercise, PacifiCorp admitted that

> Under this type of scenario, coal generation, which has traditionally served as a low cost and reliable source of base load generation, could become uneconomic when compared to alternative sources of energy. Such a scenario would impact not only PacifiCorp and its customers… but almost certainly impact the viability of coal generation across the country.[10]

Today, natural gas prices are well below even PacifiCorp's lowest envisioned gas price in early 2012, and PacifiCorp's prediction is correct: large swaths of coal-fired generation nationwide is non-economic, and consequently must retire. PacifiCorp's fleet is no exception, except that

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[7] Oregon LC 52, PUC Order 12-082 (March 9, 2012)
[8] *Id.* Action Item 9.
[9] PacifiCorp 2011 IRP Update. Available at https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRPUpdate/2011IRPUpdate_3-30-12_REDACTED.pdf
[10] *Id.* Page 88.

PacifiCorp has failed to show this Commission and other states the economic condition of its coal units.

The 2013 IRP became the first forum in which PacifiCorp allowed the System Optimizer model to select coal units for "optimal" retirement, and found that under low gas prices and moderate carbon prices, the entirety of PacifiCorp's coal fleet would be rendered non-economic by the early 2020s.[11] PacifiCorp agreed that "portfolios with low natural gas price inputs, high CO_2 prices, and high coal costs produced portfolios with significant early coal unit retirements,"[12] but dismissed the mass-retirement outcome as a fringe finding.

And while the 2017 IRP forecasts lower CO_2 shadow prices than the "high" CO_2 prices of the 2013 IRP, PacifiCorp's base-case gas and market energy price projections in 2017 are well below the "low" 2013 forecasts that led to that dramatic 2013 outcome.[13] It is plausible that many of PacifiCorp's coal units are under water based on the Company's current reference case conditions.

Following the 2013 IRP, Oregon PUC staff requested that PacifiCorp also assess the potential to negotiate "intertemporal trade-offs" with the US Environmental Protection Agency (EPA). Such a plan would serve as an alternative means of complying with the Clean Air Act's Regional Haze

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[11] PacifiCorp 2013 IRP Volume II, Appendix K Cases C-04 (pages 166, 184, 204, and 223, and 242), C-05 (pages 167, 184, 204, 224, and 243), C-08 (170, 189, 208, 227, and 247) and C-09 (171, 190, 209, 228, and 248). All coal retirements for Hunter 1-3, Huntington 1 & 2, Carbon 1 & 2, Cholla 4 (mislabeled as Cholla1), Dave Johnston 1-4, Naughton 1 & 3, Wyodak, Jim Bridger 1-4, and Colstrip 3 & 4 occur on or before 2023.
[12] Oregon Docket LC 57 (2013 IRP). Reply Comments of PacifiCorp, p. 85. http://edocs.puc.state.or.us/efdocs/HAC/lc57hac83916.pdf
[13] PacifiCorp 2013 IRP. Figure 7.14**.** Low case prices at $4.5/MMBtu in 2022 and $5.5/MMBtu in 2030. PacifiCorp 2017 IRP. Figure 1.5. Reference Case Henry Hub prices in $3/MMBtu in 2022 and $5/MMBtu in 2030.

Left to its own devices, PacifiCorp's 2015 IRP model would have chosen to retire 1,390 MW of coal from Cholla 4, Craig 1, Hayden 1 & 2, Hunter 1 & 2, and Naughton 1.

program, which pertained to most of the Company's coal units. The idea was to reach a negotiated settlement with EPA and the states so that the Company would commit to retiring some of its less economic units before the end of their depreciable lives, thereby avoiding costly emissions controls **while still meeting required emission reductions** to clean up air quality in national parks and wilderness areas.

Oregon PUC staff did not request that PacifiCorp **cease** performing economic analyses of its existing coal resources. Staff simply stated that it would "like to see more alternative compliance type analyses, including analyzing the economics of early retirement or repowering at one unit in exchange for reduced pollution control requirements at another in future IRPs and IRP updates."[14]

In the 2015 IRP, the Company interpreted this request from the Oregon PUC staff as license to cease assessing the viability of individual coal units not subject to immediate compliance obligations. Instead, the Company implemented regional haze scenarios with little or no explanation with respect to coal retirement dates. In so doing, the Company skipped any opportunity to secure savings through cost-effective coal plant retirements and restricted the System Optimizer model from making cost-effective selections. Sierra Club recognized this shortcoming and invested in a very costly System Optimizer model licensure to fill the gap left

[14] Oregon Docket LC 57 (2013 IRP). Initial comments of Staff, page 3 "Alternative Compliance Options."

by PacifiCorp. That modeling showed that, left to its own devices, PacifiCorp's System Optimizer model would have chosen – in the reference case – to retire 1,390 MW of coal from Cholla 4, Craig 1, Hayden 1 & 2, Hunter 1 & 2, and Naughton 1 in 2021. [15]

In the 2016 Report Order on the 2015 IRP, this Commission provided leeway to PacifiCorp, "recogniz[ing] the complexity surrounding the evaluation of options to comply with the CPP draft and Final Rule," but stated that "PacifiCorp will need to continue to refine its evaluation of environmental compliance options to determine least cost and least risk approaches."[16]

The Utah PSC may not have envisioned 2017 conditions in the order on the 2015 IRP, where environmental compliance options are not the driving factor behind the value of coal – instead, persistent low market prices and fundamental economics are the basis of PacifiCorp's low-value fleet.

This 2017 IRP retreats even further from transparent coal valuation, providing no opportunity to assess the cost-effectiveness of retaining PacifiCorp's coal units: either those facing required environmental retrofits, or those simply facing high fixed costs and low market revenues. The 2013 and 2015 IRPs made clear that PacifiCorp's coal plants could readily become non-economic, and subsequent analyses through litigated dockets have shown that the Company's plants have lost tremendous value in the last few years. In late 2016, the Washington UTC found

[15] Sierra Club's Comments on PacifiCorp's 2015 IRP. Docket LC 62. August 27, 2015. Appendix: Review of the Use of the System Optimizer Model in PacifiCorp's 2015 IRP. Figure 3. http://edocs.puc.state.or.us/efdocs/HAC/lc62hac134513.pdf

[16] Docket 15-035-04. Rocky Mountain Power's 2015 Integrated Resource Plan. Report and Order. Page 16.

that changing conditions had likely rendered the decision to install costly controls at Jim Bridger a non-economic decision.[17]

> *In 2016 and 2017 alone, Salt River Project decided to close Navajo Generating station, Idaho Power acknowledged that North Valmy should retire expediently, Arizona Public Service shut down Cholla 2 and announced the cessation of coal operations at Cholla 1 & 3, and Public Service Company of New Mexico announced that it was considering shutting down San Juan in 2022. Not one of those decisions was driven by an environmental capital requirement.*

The valuation of an existing generating resource is a straightforward exercise in which the costs of continuing to operate (and pay for incremental fixed O&M and capital) are assessed against a reasonable alternative – or a least-cost replacement portfolio. This simple exercise is a critical part of modern resource planning: are ratepayers better off continuing to operate an existing resource, or retire that resource and find more cost-effective supply options? While we know that PacifiCorp regularly runs this type of assessment in-house, employing both simple and complex tools, the IRP dodges the question all together, continuing to kick the can down the road to a "future IRP or IRP Update."[18]

According to PacifiCorp's 2017 action plan, future coal economic assessments will be based on whether the Company Regional Haze obligations are reduced in Utah and Wyoming. The argument that coal plants only require assessment in the face of large capital decisions is wrong and disingenuous. While in 2012, we had an emerging concept that existing coal units might be

[17] Washington UTC Docket UE-152253. Order 12. September 1, 2016. "We find that Pacific Power's failure to re-evaluate its options in the face of changing economic circumstance, including inputting this information into the Company's System Optimizer model during this six-month period, exposed ratepayers to considerable risk." https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=2289&year=2015&docketNumber=152253

[18] PacifiCorp 2017 IRP, Table 1.4 - 2017 IRP Action Plan. Items 5a through 5h. Each item promises to "provide the associated analysis in a future IRP or IRP Update."

non-economic in the face of large new capital requirements, the paradigm has shifted nationally. It is now very possible for coal plants to be dramatically non-economic, even with a secure fuel supply and no pending large capital requirements. Indeed, PacifiCorp's neighboring utilities recognize – and act – on this knowledge. In 2016 and 2017 alone, Salt River Project decided to close Navajo Generating station, Idaho Power acknowledged that North Valmy should retire expediently, Arizona Public Service shut down Cholla 2 and announced the cessation of coal operations at Cholla 1 & 3, and Public Service Company of New Mexico announced that it would shutter San Juan Generating Station in 2022. Not one of those decisions was driven by an EPA regulation requiring capital expenditures.

In 2017, has PacifiCorp demonstrated that ratepayers are better off continuing to pay for high fixed costs at its existing coal units? No. The closest the 2017 IRP gets to providing valuable information is in its Regional Haze Case 6; but, as we demonstrate, that case is irretrievably flawed. In short, PacifiCorp has denied stakeholders and the Commission the opportunity to determine whether ratepayers are well-served through the continued reliance on coal generation– a critical and fundamental issue.

2.1. "Endogenous" Coal Retirements and Regional Haze Case 6

The Company's complex System Optimizer model provides a default mechanism to assess cost-effective retirements, referred to by the Company as "endogenous retirements."[19] This is an option which the Company fought vehemently to avoid employing, insisting instead that it would

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[19] "Endogenous: having an internal cause or origin."

not allow this evaluation option at its public input meetings. In response, on August 25, 2016, Sierra Club, Idaho Conservation League, HEAL Utah, NW Energy Coalition, Western Clean Energy Campaign, and Powder River Basin submitted detailed comments back to PacifiCorp, rebutting each of the Company's arguments on why endogenous retirement should not be included. The key turning point came when Sierra Club agreed to settle a coal procurement case before the California PUC if PacifiCorp agreed to run just one endogenous coal retirement case in the 2017 IRP and evaluate it on an equal footing. In that settlement, the Company agreed that:

> In establishing Regional Haze assumptions for its 2017 IRP, PacifiCorp will include a Regional Haze case that allows endogenous coal unit retirements (defined as Regional Haze case 6 in the September 22-23, 2016 IRP public input meeting presentation) and commits to evaluating this case among the same market price and greenhouse gas policy assumptions that will be used to evaluate other Regional Haze cases.[20]

PacifiCorp declined to assess its stake in Naughton 1 & 2, Jim Bridger 3 & 4, Dave Johnston 1 - 4, Wyodak, Hayden 1 & 2, or Craig 1 & 2.

Regional Haze Case 6 represents one of two scenarios in which PacifiCorp meets EPA's final regional haze requirements as described in the Federal Register, the other case being the Reference Case. PacifiCorp's legal obligations under the Regional Haze program are described later in these comments.

It is unfortunate that PacifiCorp only agreed to perform fundamental resource planning via a quid pro quo settlement term to end an unrelated contested proceeding in California. Even then, it is our position that PacifiCorp largely failed to uphold the settlement term. In the one circumstance

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[20] CPUC Docket A.15-09-007. Joint Motion of PacifiCorp, Sierra Club, and the Office of Ratepayer Advocates for Adoption of Settlement Agreement. February 6, 2017. Section 2.6. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M175/K636/175636109.PDF

where PacifiCorp allowed the endogenous retirement option, it limited the assessment to just six units – Units 1 & 2 of Hunter, Huntington and Jim Bridger.[21] According to the Company, “only those coal fueled units where a major decision on emissions compliance investment would be required as part of an ongoing federal and/or state Regional Haze implementation plans process were analyzed.”[22] This means that PacifiCorp declined to assess Naughton 1 & 2, Jim Bridger 3 & 4, Dave Johnston 1 - 4, Wyodak, Hayden 1 & 2, or Craig 1 & 2.[23] Nonetheless, PacifiCorp’s modeling found that, given a Regional Haze compliance obligation, Jim Bridger Unit 2 would retire in 2021.[24]

Without a PacifiCorp assessment of its existing coal fleet, Sierra Club was compelled to use the Company’s disparate data to construct a screening analysis of its own to assess cost-effective coal retirements.

2.2. Cost-Effective Coal Retirements in the 2017 IRP

Using only data from the 2017 IRP, Sierra Club determined that nine units, representing nearly one-third of PacifiCorp’s coal boilers, are non-economic relative to market-based energy and capacity if replaced in 2018 – even without factoring in required regional haze retrofits. These non-economic units include Cholla 4, Craig 1, Craig 2, Hayden 1, Hayden 2, Jim Bridger 3, Jim Bridger 4, Naughton 1, and Naughton 2. Jim Bridger 1 & 2 are distinctly marginal, and Dave

[21] 2017 IRP Table 7.10.
[22] Sierra Club DR 1.3
[23] The Company provides some analysis on the economics of operating or converting Naughton 3 and Cholla 4, both of which were identified in prior planning processes as non-economic.
[24] 2017 IRP, page 185.

Johnston 1 is not far behind. We estimate that maintaining units with liabilities above $60/kW past 2018 will incur ratepayer losses of nearly $600 million (NPV 2016$, 2017-2036).[25] Confidential Figure 1, below, shows the valuation of each PacifiCorp coal unit in dollars per kW, as derived from System Optimizer (SO) fixed costs and generation from SO and Planning and Risk (PaR), respectively (as explained below). The units with negative valuations are net liabilities to ratepayers – i.e. ratepayers would be better served with the expedient retirement of these units.

Confidential Figure 1. Valuation of PacifiCorp coal units (2016 $/kW NPV 2017-2036), Preferred Portfolio. Negative values indicate net liabilities.

[redacted]

[25] Generation and fuel consumption from PaR (FS-GW4).

Accounting for regional haze requirements in Utah and Wyoming, we find that Jim Bridger 1 & 2 are also non-economic, resulting in an incremental [redacted] in ratepayer losses (NPV 2016$, 2017-2036),[26] as shown in Confidential Figure 2, below.

We constructed this analysis using unit-specific information from PacifiCorp's inputs for the SO model and outputs from both SO and PaR. All input data, assumptions and structures are based on PacifiCorp-provided data from the 2017 IRP. From the inputs, we drew annual capital requirements (environmental and non-environmental), as well as operations and maintenance costs. We drew on SO and PaR for annual generation and fuel costs. Coal plant capital costs (including ratable shares of plant common capital) were amortized across the PacifiCorp assumed plant life.

[26] Generation and fuel consumption from PaR (Reference Case).

Confidential Figure 2. Valuation of PacifiCorp coal units (2016 $/kW NPV 2017-2036) with Regional Haze investments (Reference Case). Negative values indicate net liabilities.

[redacted]

For replacement resources, we followed PacifiCorp's assumption that there is ample market-based energy and capacity available at reasonable prices. This assumption is reflected in PacifiCorp's front office transaction (FOT) calculations which assume 1,670 MW of market-available capacity,[27] priced at approximately the cost of market-available energy.[28]

[27] 2017 IRP Table 1.2. PacifiCorp 10-Year Summer Capacity Position Forward (MW) and Table 5.14 – Summer Peak – System Capacity Loads and Resources without Resource Additions.

[28] SC DR 1.13(a). "The pricing for Front Office Transactions (FOT) are pulled directly from the October 2016 electric and gas price curves used in the 2017 Integrated Resource Plan (IRP) and input into the System Optimizer model (SO Model) on a monthly basis for the heavy load hour (HLH) and flat products. A bid/ask spread is included for FOTs."

Each coal unit's ongoing costs were assessed against Mid-Columbia energy prices.[29]

For the years 2016 and 2017, we assumed that existing coal units continued to operate, and all capital incurred in those two years was treated with accelerated deprecation to 2018. For every year after 2018, we assumed that the forgone generation from the unit was replaced with market energy. In this analysis, we do not assume a capacity price or particular capacity value for the existing coal units, consistent with PacifiCorp's assumptions that there is ample regional capacity in the form of firm market energy purchases (FOTs).

Nearly 1/3rd of PacifiCorp's coal fleet is non-economic ***even in the absence of required regional haze retrofits.***

We compared the annual cost of the coal plant against the annual replacement cost, and took the net present value of the difference as an indication of the plant's valuation.

An example for Hunter 3, a unit assessed by this analysis as relatively economic, is shown below in Confidential Figure 3, showing the annual cost (nominal $) of Hunter and equivalent replacement energy. This figure shows that [redacted]

[29] Mid-Columbia FOTs are the most readily available FOT (see 2017 IRP, Table 6.16), and first chosen resource (see 2017 IRP, Volume II. Appendix K, all plans). For the purposes of evaluating DSM costs, PacifiCorp assesses the value of all DSM bundles against Mid-Columbia prices (see 2017 IRP, page 138, footnote 9 – "The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.")

[redacted] relative to retirement in 2018.

Confidential Figure 3. Annual costs for Hunter 3 and replacement cost (Mid-Columbia after 2018).

[redacted]

In contrast, all three Naughton units pose substantial financial risk to PacifiCorp, as illustrated in Confidential Figure 4, below. At an average [redacted] capacity factor (2018-2029),[30] [redacted]

[30] PaR run for Preferred Portfolio, mid-gas prices, CPP-B.

[redacted] even just through its proposed retirement in 2030.

Confidential Figure 4. Annual costs for Naughton 1 and replacement cost (Mid-Columbia after 2018).

[redacted]

Naughton 1 is not currently facing any substantial environmental retrofits over the span 2017-2022, but it will likely be subject to the Regional Haze Rule's "reasonable progress" requirements that pertain to **all stationary air pollution sources**. The reasonable progress requirements could mandate NOx controls. Nevertheless, the unit is clearly a substantial ratepayer liability. PacifiCorp has no mechanism by which it assesses the viability of existing coal plants, and by ignoring its existing coal generators in the 2015 and 2017 IRPs, glosses over any indication that these units impose massive, unnecessary costs to ratepayers.

These analyses indicate that current spending at Naughton and many of PacifiCorp's other units may be imprudent, and the Company should be assessing the near-term retirement of a substantial component of its fleet. Its IRP analysis however, gives no indication of these liabilities because its plan is specifically designed to obscure such facts and results.

In 2017, it is clear the Commission must finally direct PacifiCorp to analyze, as part of its fundamental planning process, the viability of each individual coal unit, demonstrating that continued operation is in ratepayers' interest. The data provided by PacifiCorp strongly indicates economic weakness.

PacifiCorp's data shows that the recently retrofit Jim Bridger 3 & 4 units will incur substantially higher costs than they could otherwise recover if they operated as merchant plants. With fixed costs in excess of [redacted] Notably, our analysis assumes that all previously incurred costs – including the costs of the recently installed selective catalytic reduction NOx controls (SCR) – are recovered, effectively assuming that ratepayers will incur these costs irrespective of retirement or continued operation of the plant. This is an important distinction, fully consistent with PacifiCorp assumptions. To exclude those costs – as if they were never completed or disallowed in rates if Bridger retired – would result in a yet stronger case for retirement.

In short, even though PacifiCorp invested hundreds of millions to install and operate SCR control technology at Jim Bridger 3 & 4, the Company's data shows that these units are already a liability on a forward-looking basis. Confidential Figure 5, below, shows the visual representation of cash flows at Bridger 3 & 4 from 2017 to 2036 relative to the replacement energy option.

Confidential Figure 5. Annual costs for Jim Bridger 3 & 4 and replacement cost (Mid-Columbia after 2018). Assumes all existing SCR costs are sunk.

[redacted]

Jim Bridger 1 & 2 are facing a near-term decision with respect to the installation of SCRs. Our re-analysis of PacifiCorp's data indicates that, irrespective of the SCR requirement, Jim Bridger 1 & 2 are economically marginal. In fact, PacifiCorp's data indicates that Jim Bridger 1 will not provide value through the end of its RH-5 life in 2028, and Bridger 2 will only provide a ratepayer benefit after [redacted]

Adding the SCR requirement to Jim Bridger 1 & 2 makes the hurdle to economic value that much higher. Both Bridger 1 & 2 only show economic value after [redacted], and do not make enough revenue after that time to justify the SCR investments in the early 2020s. Even if Bridger 1 & 2 were projected to make substantial revenue at that late date, the Company would be taking a massive risk, asking ratepayers to support the expenditure on a hope that the plant would become economically viable at a much later date. The analysis – including both the "Preferred Portfolio" case where the SCRs are avoided and the "Reference Case" where the SCR costs are incurred, are shown in Confidential Figure 6, below.

Confidential Figure 6. Annual costs for Jim Bridger 1 & 2 and replacement cost (Mid-Columbia after 2018). Top row assumes no SCR investments and RH-5 retirement schedule. Bottom row assumes SCR investment and continued operation.

[redacted]

2.3. PacifiCorp's Updated 2017 Wind/Transmission Analysis Impacts on Coal

On June 30, 2017, PacifiCorp filed docket 17-035-40, its Voluntary Request for Approval of Resource Decision on the new wind and transmission lines in Wyoming. Although the resource decision fell closely on the heels of the 2017 IRP the Company's analysis in that docket relies on a new set of gas price assumptions, and importantly, assumptions about future carbon pricing risk. Rather than relying on an assumption that a mass CPP-like cap will be binding, the Company reverts to carbon pricing starting in 2025.[31] The Company takes pains to explain that the projects will "help decarbonize PacifiCorp's resource portfolio, which will mitigate long-term risk associated with potential future state and federal policies targeting carbon dioxide ("CO_2") emissions reductions from the electric sector."[32] Most importantly, **in 17-035-40, the Company asks the Commission to take into account new carbon pricing when assessing the value of the new wind and transmission projects**, stating that customers would realize a $137 million benefit.[33] The difference between an assumption of carbon pricing and no carbon pricing in the Company's mid-gas case is $84 million,[34] or a majority (60%) of the net benefit of the project.

The Company seeks authorization of nearly $3 billion in new capital for transmission and wind, relying on an assumption of future CO_2 pricing to exact a marginal ratepayer benefit while completely ignoring a billion dollars of net liabilities in their existing fleet.

The new assumptions in 17-035-40 impact the fundamental economics of the Company's coal units, a fact that simply doesn't play into the Company's plea in that clean energy docket and demonstration of a radical double standard: carbon risk and reduction matters when the Company is seeking clean energy projects, but not when it is charged with reviewing the economics of its largest emissions sources.

[31] Docket 17-035-40, Direct Testimony of Rick Link, page 34 at 743-750 and page 35 at Figure 2.
[32] Docket 17-035-40, Direct Testimony of Rick Link, page 3 at 51-53.
[33] Docket 17-035-40, Application at page 9; Direct Testimony of Cindy Crane, page 2 at 28, page 5 at 94, and page 11 at 240 and 247; Direct Testimony of Rick Link, page 4 at 74, and page 39 at 822; Direct Testimony of Jeffrey Larsen, page 4 at 74.
[34] Docket 17-035-40, Direct Testimony of Rick Link, page 38, table 3.

Under the revised carbon pricing presented in 17-035-40, more than half of the Company's coal generation (by capacity) is non-economic – even with an assumption that Regional Haze obligations simply cease to exist. Little of PacifiCorp's fleet has customer value on a going-forward basis. Confidential Figure 7, below, shows that fifteen units have higher all-in costs on an NPV basis over their "preferred portfolio" lives than market energy and capacity. Included in this list are Hunter 1, Cholla 4, Colstrip 3 & 4, Craig 1 & 2, Jim Bridger 1-4, Hayden 1 & 2, Naughton 1 & 2, and Craig 2. In total, the non-economic plants incur **$1.14 billion** in losses.

Confidential Figure 7. Valuation of PacifiCorp coal units (2016 $/kW NPV 2017-2036), Preferred Portfolio with updated carbon pricing from 17-035-40. Negative values indicate net liabilities.

[redacted]

Under this analysis, plants like Jim Bridger 3 & 4 **never recover** their fixed costs. By a long margin, Jim Bridger exacts the largest cost on ratepayers, losing [redacted] **each year** from 2019 to 2028, and exacting a net cost of over a billion dollars (NPV) on ratepayers.

It is astounding that the Company currently seeks authorization of nearly $3 billion in new capital for transmission and wind, relying on an assumption of future CO_2 pricing to exact a marginal ratepayer benefit while completely ignoring a massive and persistent cost representing a ratepayer liability an order-of-magnitude larger.

How should the IRP treat existing coal generation? Integrated resource planning is meant to be, at its best, just that – a forecasting and long-term resource management structure that allows the utility, regulators, and stakeholders to assess multiple aspects of the utility system and propose utility and regulatory changes that will meet ratepayer and utility needs. IRPs tend to gravitate towards specific resource questions: new market structures, policies, regulations, and resource choices, but in general must account for the pertinent questions facing the utility. PacifiCorp has structured an IRP process that specifically precludes the opportunity to assess the most pertinent – and persistent – question facing the utility: is there a ratepayer benefit from the continued use of coal?

PacifiCorp's IRP sidesteps answering this central question. Still, anywhere from a third to half of the Company's coal units are arguably non-economic today under PacifiCorp's forecast conditions with no incremental environmental retrofits. PacifiCorp can no longer take the position that decisions about the existing coal fleet can just be continuously deferred or await litigation outcomes. Irrespective of that litigation – or EPA's Regional Haze deadlines – **Jim Bridger 1-4 are non-**

PacifiCorp has structured an IRP process that specifically precludes the opportunity to assess the most pertinent – and persistent – question facing the utility: ***is there a ratepayer benefit from the continued use of coal?***

economic today with liabilities in excess of a billion dollars. Outside of any Regional Haze argument, Naughton 1 & 2 pose a [redacted] liability today. Craig and Hayden, [redacted]

The IRP process must provide a fair and candid ongoing assessment of the Company's coal generating resources, and must not exclude the assessment of existing resources simply because it chooses to leave such assessments out of view.

3. PacifiCorp's Regional Haze Requirements

One of the most important aspects of PacifiCorp's long-term planning over the last decade has been how the Company expects to meet Clean Air Act requirements under EPA's Regional Haze program. For example, in 2007, the Company began the process of installing very expensive flue gas desulfurization technology to control for SO_2 (FGD or "scrubbers" and scrubber upgrades) at Naughton and Hunter units prior to any final legal requirement to do so.[35] The cost-benefit analysis of those decisions revealed that the Company's coal-fired units could be substantially non-economic in the face of Clean Air Act requirements.[36]

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[35] See Oregon Docket UE 246, General Rate Case, Order 12-493 disallowing certain retrofit costs from rates for inadequate assessment of economic viability. See also Wyoming Docket 20000-384-ER-10 (Record 12702), General Rate Case, Order on September 22, 2011 approving stipulation for future CPCN requirements.

[36] See Wyoming Docket 20000-400-EA-11 (Record 12953). Naughton 3 SCR CPCN. Company withdrew application upon finding that Naughton was more cost-effectively re-fired with gas than retrofit with SCR for compliance purposes.

The Company's Preferred Portfolio does not meet EPA's on-the-books compliance obligations and cannot be accepted as "better than BART."

As a result, the 2013 IRP contained the first comprehensive forward-looking economic analysis for coal plants with pending Regional Haze obligations – at the time, Hunter 1 and Bridger 3 & 4. In that IRP, the Company continued to assume for base planning purposes that both Hunter and Bridger would meet environmental compliance obligations as proposed, or otherwise retire. That 2013 IRP was the only planning process conducted by PacifiCorp that allowed the existing coal fleet to retire economically if the model found a more cost-effective pathway.

In the 2015 IRP, the Company shifted its approach, offering what it termed "Regional Haze Scenarios," in which PacifiCorp searched for "different inter-temporal and fleet-tradeoff compliance outcomes."[37] These alternatives were ostensibly designed to help PacifiCorp develop reasonable negotiating positions with EPA to comply with Clean Air Act requirements to achieve "better than BART" results under various state Regional Haze rules. The idea was to potentially avoid installing expensive pollution controls at specific units, by instead exploring a balanced selection of early retirement options coupled with lesser controls, all to achieve emissions results better than EPA's regional haze rules for Wyoming and Utah. Done properly this would be a win-win solution for ratepayers and air quality. According to PacifiCorp, it conducted these analyses in 2015 at Oregon Commission staff's request because prudent planning required exploration of lower cost compliance pathways comparable to the negotiated settlements at the Boardman and Centralia coal plants. However, while the 2015 IRP relied on

[37] 2015 IRP, page 15.

these regional haze outcomes, the Company did not show whether its own alternatives could achieve better emissions results, i.e., visibility improvements, over EPA's requirements.[38]

The 2017 IRP again focuses on Regional Haze Strategies (now called "Alternatives"), but now in a way that misrepresents the Company's actual legal obligations under the Regional Haze program in Wyoming and Utah. The vast majority of the Company's modeling in the 2017 IRP, and the Company's preferred portfolio, cannot meet enforceable Clean Air Act requirements. Because PacifiCorp could not today legally implement its preferred portfolio, it is Sierra Club's view that PacifiCorp is doing a great disservice to its regulators and customers by misrepresenting the true status of its legal status under the Clean Air Act.

To be clear, the Company faces final EPA compliance obligations at **Hunter 1, Hunter 2, Huntington 1, Huntington 2, Jim Bridger 1, Jim Bridger 2, Dave Johnston 3, and Wyodak.** The Company's preferred portfolio wrongly assumes that these legal requirements need not be met, and that instead PacifiCorp may simply install lesser controls at a time of its choosing.

Sierra Club is concerned about the Company's Regional Haze "Alternatives" because:

- As described, the alternatives cannot meet EPA's Clean Air Act technical requirements;
- For planning purposes, PacifiCorp assumed it will prevail in litigation even though EPA has rarely lost regional haze litigation brought against it;
- The alternatives obscure the actual costs of operating PacifiCorp's coal plants; and

[38] In the 2015 IRP, the Company did provide confidential workpaper "screening models" that appear to have been used to select which units should be taken offline for compliance purposes. It offered no such workpapers in the 2017 IRP.

- The Company is unwilling to disclose the basis or mechanisms by which it developed its alternative regional haze strategies.

3.1. PacifiCorp's Regional Haze Alternatives were not shown to meet EPA's technical requirements for "Better than BART"

The Clean Air Act's Regional Haze program requires states to meet certain visibility milestones in order to restore air quality in national parks and wilderness areas by 2064. The first aspect of the program required power plants constructed between 1962 and 1977 to install Best Achievable Retrofit Technology (BART) to meet unit-specific emission limits. States, working with utilities, drafted implementation plans to submit to EPA for approval based on a five-factor analysis.[39] BART retrofits reduce sulfur dioxide (SO_2) and oxides of nitrogen (NOx) which are precursors to visibility – and health – impairing particulates and ozone. In the alternative, the Regional Haze program provided states and entities the opportunity to propose BART alternatives that were technically shown to be "better than BART," i.e., achieving visibility improvements at or better than those achievable through strict implementation of BART.

PacifiCorp's Regional Haze Alternatives aims to mimic the regional haze program's "better than BART" approach utilized at Boardman, Centralia, and San Juan coal-fired plants. However, the IRP evidences no engagement on the Company's part with the appropriate state air quality agencies or EPA to verify the "Alternatives" technical compliance with the Better than BART option. Better than BART provides utilities with flexibility if they commit to retiring some

[39] The five-factor analysis: (1) the costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and, (5) the degree of visibility improvement which may reasonably be anticipated from the use of BART.

noneconomic units at a date-certain (Boardman and Centralia); or, retire some units at a date-certain while installing lesser controls on other units (the retirement of San Juan 2 & 3). **In all cases, the EPA-approved alternative plans achieved the required emission reductions at the affected Class 1 areas.** Unlike these relatively simple single-plant tradeoffs, PacifiCorp has loosely proposed a whole fleet strategy, with a series of retirements and lesser retrofits that it believes would meet the Better than BART criteria, absent any emissions or visibility analyses to support such a plan.

A Better than BART alternative requires a careful – and highly technical – assessment of the visibility implications of foregoing near-term unit-specific retrofits. In PacifiCorp's case, EPA has finalized BART retrofits between 2019 and 2022 in both Wyoming and Utah, although the Company sued EPA over both plans.

Below, we compare the Company's Preferred Portfolio – it's planning case – against the Reference Case; the reference case is the only one in which PacifiCorp meets EPA's final Regional Haze rules for Wyoming and Utah. As shown in Confidential Figure 8, the Company's projected emissions of SO_2 in the Preferred Portfolio are effectively identical to the Reference Case, only diverging in 2030, primarily due to the continued use of Jim Bridger 1 & 2 in the Reference Case.[40] There is no substantive improvement for the Preferred Portfolio until this very late date.

[40] Notably, in the more cost-effective RH-6 plan with endogenous retirement, Jim Bridger 2 is absent and thus SO2 emissions from the Preferred Portfolio are effectively identical to RH6.

Confidential Figure 8. SO2 Emissions under the Reference Case (Ref) and Preferred Portfolio (FS-GW4)[41]

[redacted]

With respect to NOx emissions, however, the Company's Preferred Portfolio is far worse than BART. Confidential Figure 9, below, shows that the Preferred Portfolio is consistently higher than the Reference Case by 10,000 to 13,000 tons NOx every year from 2023 to 2032, or an average of 58% higher from 2022 to 2037.[42] Over the course of the analysis period, the Preferred Portfolio releases 165,000 tons of NOx more than the Reference Case, despite the earlier retirement schedules. Under any reasonable scenario, EPA could not make the required technical findings to support a Better than BART alternative for Wyoming and Utah.

[41] Fuel consumption (GBtu) from PaR runs; emissions rates from SO Master Input files.
[42] As derived from Preferred Portfolio fuel consumption (mid-gas, CPP compliance pathway "B", Planning and Risk run output) multiplied by PacifiCorp anticipated emissions rates from System Optimizer input files as provided in workpapers.

Confidential Figure 9. NOx Emissions under the Reference Case (Ref) and Preferred Portfolio (FS-GW4)

[redacted]

3.2. PacifiCorp assumes for planning purposes that it will prevail in its Clean Air Act litigation against EPA

As mentioned above, PacifiCorp sued EPA over its final BART determinations for Wyoming and Utah.[43] It appears PacifiCorp has baked winning its cases against EPA into the 2017 IRP. This gamble is inappropriate because long-term planning is, by nature, a conservative exercise geared towards "no regrets" actions. Planning on the basis of a litigated outcome and making no contingency for losing its cases against EPA, PacifiCorp exposes its customers to extensive and unnecessary risks.

If PacifiCorp loses its cases, the Company faces retire/retrofit decisions at seven units within four years (2021/2022). Litigation is not a reasonable smokescreen and should not be used to

[43] 2017 IRP, page 36.

omit consistent analyses of the Company's legal obligations. Allowing the Company to continue to use litigation as a reason not to assess least-cost planning disenfranchises stakeholders and the Commission from transparent and frank assessments. PacifiCorp has shown no intention of providing the required information, instead stating that "PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update." This could mean the 2018 IRP Update, a 2019 IRP, or an out-of-cycle update at such time that PacifiCorp unilaterally choses to take action.

Illustrative of the problem is Wyodak. In the 2017 IRP, the Company has simply omitted from the Preferred Portfolio the upcoming SCR requirements at its Wyodak coal plant in Wyoming. Instead, the Preferred Portfolio assumed that Wyodak is not retrofitted at all, and continues to run indefinitely despite EPA-mandated pollution controls in 20191.

This problem is not new in the 2017 IRP. In the Report and Order on the 2015 IRP, this Commission noted that "UCE and Interwest also argue the Preferred Portfolio relies on a litigation strategy to avoid installation of Selective Catalytic Reduction ("SCR") control devices on coal plant units."[44] Seeking to resolve the impasse, this Commission wrote "We urge PacifiCorp to give priority in the public process of its 2017 IRP to discuss and weigh alternative approaches for determining the least cost path, adjusting for risk and uncertainty, for addressing

[44] Docket 15-035-04. Rocky Mountain Power's 2015 Integrated Resource Plan. Report and Order. Page 13.

federal environmental compliance requirements."[45] PacifiCorp did not heed the Commission's guidance, again relying on a litigation strategy, and avoiding any analysis of the existing coal fleet to meet a "least cost path."

3.3. Regional Haze Alternatives obscure actual costs of operating PacifiCorp coal plants

As shown in Section 2 ("Economics"), above, the Company's 2017 IRP failed to allow for a reasonable assessment of the Company's existing coal fleet – either on a unit-by-unit basis or in aggregate. As we show, much of the Company's coal fleet is non-economic today, irrespective of the disposition of the Regional Haze rule or impending capital requirements. The Company has instead substituted a mechanism by which aggregate "strategies" are tested against each other, with no resolution on the appropriate disposition or economics of individual coal units. This shortfall lies in stark contrast to both other utilities facing similar obligations and even the Company's 2013 IRP.

3.4. PacifiCorp is unwilling to demonstrate the basis of its Regional Haze Alternatives

The creation and full explanation of the Regional Haze strategies are critical to this IRP. However, PacifiCorp refused to disclose how it developed the strategies, nor would it provide any workbooks that support the strategies, or any communications that may have explained those strategies. There is no information in the IRP with respect to the regional haze tradeoffs, and PacifiCorp provided no workpapers to support the strategies in response to Sierra Club requests.

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[45] Docket 15-035-04. Rocky Mountain Power's 2015 Integrated Resource Plan. Report and Order. Page 16.

The regional haze alternatives represent how the Company expects to handle nearly [redacted] in potential capital requirements four years from now (and contract commitments within two years at the latest). Given the urgency of these decisions, Sierra Club requested a description of the process the Company used to develop each of the Regional Haze Alternatives. PacifiCorp responded with:

> The regional haze scenarios were developed to reflect a range of plausible compliance alternatives with a graduated path to reduce emissions and provide relative cost information between cases. The overall intent was to provide a bookended set of information that reflects the balance between emission reductions and potential cost impact on customers while also meeting customers load and resource needs. The process used was simply to reflect current compliance obligations in the reference case and then to reflect graduated alternative compliance approaches out through the end of depreciable life for individual units for the review and consideration of IRP stakeholders.[47]

The Company omitted any technical or economic analyses of how PacifiCorp targeted specific units, established particular dates, or supported lesser emissions controls to "reflect graduated alternative compliance approaches" in conformance with Clean Air Act requirements.

PacifiCorp has a duty to provide the Commission and stakeholders with evidence, showing how the 2017 IRP's regional haze alternatives will meet EPA requirements under the Clean Air Act.

Sierra Club also requested that PacifiCorp provide any workpapers used to develop the Regional Haze alternatives, "including assessments of timing and type of alternatives, estimated emission reductions from compliance alternatives, visibility impairment mitigation, cost effectiveness on a

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[46] Confidential Workpapers, SO Master Assumptions, 2017 IRP Ref Case 20161021.xlsx, tab "1b – Clean Air CapEx."
[47] SC DR 1.1(a)

per-ton or per deciview basis, Best Available Retrofit Technology (BART) equivalency, or "better than BART" applicability."[48] PacifiCorp responded that those workpapers were included in the confidential master assumptions workbooks. A careful review of each and every workbook and tab reveals **no information** about timing and type of alternatives, estimated emission reductions from compliance alternatives, visibility impairment mitigation, cost-effectiveness on a per-ton or per deciview basis, BART equivalency, or "better than BART" applicability.

Sierra Club believes that PacifiCorp has a duty to provide the Commission and stakeholders with evidence, e.g., legal and technical support papers, showing how the 2017 IRP's regional haze alternatives could meet EPA requirements under the Clean Air Act. PacifiCorp refused.

Next, asked to "identify and provide legal memoranda, presentations, white papers or communications supporting the development or continued use of RH-1 through RH-5," and "identify originating party, receiving party, date, and topic," PacifiCorp stated that:

> The IRP itself and presentation materials discussing and detailing Case RH-1 through Case RH-5 are responsive to this request.[49]

Again, scouring each of the stakeholder presentations, in which Sierra Club was a very active participant, the IRP and IRP appendices, we find no materials that show if or how the Regional Haze alternatives could pass EPA muster. PacifiCorp's answer, citing only the public presentation materials, shows that PacifiCorp did not have internal discussions or conduct any analyses on the potential viability of the Regional Haze alternatives.

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[48] SC DR 1.1(b)
[49] SC DR 1.1(e) & (f)

Finally, Sierra Club asked whether PacifiCorp was of the "opinion that the US EPA would be indifferent to the selection of the Reference Case against any of the portfolios RH-1 through RH-6."[50] PacifiCorp objected, stating that a response would require a legal opinion or speculation. PacifiCorp wrongly falls back on formalistic legal objections asserted against opposing counsel when answering discovery questions at trial. Sierra Club made clear it was not seeking attorney-client or other privileged materials from the Company; instead, we were merely seeking the legal justification for the foundation of the coal generation aspect of the 2017 IRP.

Sierra Club finds the Company's defensiveness unproductive. One of the most important guiding elements of PacifiCorp's IRP – and decisions over the last decade – is the Company's position on how it will meet upcoming Clean Air Act obligations. PacifiCorp has now refused to provide any basis or support for its assumptions and assertions. According to the Company, PacifiCorp's Regional Haze compliance alternatives appear to be based entirely on the subjective judgement of three individuals – Chad Teply, Bill Lawson, and Irene Heng,[51] with no analytical or legal support whatsoever.

4. WIND REPOWERING

In the 2017 IRP, PacifiCorp contemplates "repowering" existing wind turbines in 2019 and 2020, upgrading 905 MW of existing wind[52] to increase capacity factors by about [redacted]

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[50] SC DR 1.2(d)
[51] SC DR 1.1(c)
[52] 2017 IRP, p234.

[redacted], the equivalent of adding about [redacted] of new Wyoming wind capacity to the system.[53] The Company attributes this decision to its ability to increase capacity factors at existing wind farms, contribute to RPS and environmental policy compliance, and take advantage of federal production tax credits ("PTC") before the provisions sunset. PacifiCorp's wind repowering project appears to take advantage of a PTC provision in which the Company's incremental repowering investment is able to harness the entire PTC as if the project were a greenfield investment, rather than repowered projects. As individual projects, the repowering appears to be substantially less cost-effective than new wind – and replaces generation projects that are less than a decade old.

The PTC may be available to a wind repowering project, so long as certain criteria are met. The Internal Revenue Service established a framework whereby a wind repowering project was eligible for the PTC so long as "the fair market value of the wind power facility's used property is not more than 20% of the wind power facility's total value."[54] In other words, the wind repowering project must cost four times the market value of the remaining components of the existing project, including land and tower components. If a project abides by the so-called 80/20 test, then it would lock in the PTC for 10 years at the step-down rate associated with the year in which construction begins – 80 percent of the PTC in 2017, 60 percent in 2018 and 40 percent in 2019.

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[53] Derived from Confidential workpaper "Wind Repower Data Fixed Cost & PTC." Repowering increases energy output from wind farms from [redacted], or an improvement from net 33% capacity factor to [redacted]

[54] PWC. Wind PTC motivates gust of activity in wind power facility repowering. 2016. http://www.pwc.com/us/en/power-and-utilities/publications/assets/pwc-wind-ptc-repowering.pdf

Recently, the idea to repower wind turbines has gathered steam as a means to take advantage of federal tax credits before they expire. Many turbines in place today are reaching the end of their existing, 10-year PTC schedule. Faced with the prospect of no longer receiving the PTC, certain utilities have already begun to repower their wind fleets. For instance, NextEra repowered 327 MW of wind across two sites in Texas in 2016, and seem poised to continue the practice in the future.[55] Additionally, Leeward Renewable Energy ended 2016 with a project to turn a 52 MW wind farm into a 73 MW, repowered facility.[56] Given the overlapping years of expiring credits from original PTC schedules and the potential to harness federal tax credits once again in the near term, repowering wind appears to be a legitimate, if not entirely standard, business practice.

While PacifiCorp's decision to repower wind alone may be savvy business it does not necessarily have a substantial public benefit.

While PacifiCorp's decision to repower wind alone may be savvy business, it does not necessarily evidence a substantial public benefit, but instead draws a contrast to the Company's treatment of its existing coal fleet. The wind farms at issue here are almost all less than a decade old (Glenrock, Seven Mile, High Plains, Dunlap Ridge, Rolling Hills, and Marengo) with nearly twenty years of depreciable life remaining. PacifiCorp expects to forgo most of that capital investment (but presumably not the rate recovery on that capital) replacing it with marginally better wind. The marginal costs of the wind repowering project are extremely poor without the PTC. The [redacted], or [redacted] capacity equivalency is expected to cost about [redacted], or an

[55] https://www.snl.com/Interactivex/article.aspx?CdId=A-37220265-13360
[56] http://www.utilitydive.com/news/zombie-wind-and-solar-how-repowering-old-facilities-helps-renewables-keep/429047/

equivalent [redacted] higher than the cost of a new project. Of course, PacifiCorp estimates that federal tax credits make up for this conspicuous shortfall.

The wind repowering projects may prevent PacifiCorp from harnessing other economic wind on the system. PacifiCorp's sensitivities demonstrate that a significant segment of wind – more than a gigawatt – is economically procured by the model, irrespective of the wind repowering projects, when additional transmission in made available. By expending capital and transmission resources to repower wind, PacifiCorp may be missing an opportunity to increase the amount of new wind on the system.

5. Gateway Transmission

The overall Gateway West project is a proposed 1,000-mile, high-voltage connection between Windstar substation in Wyoming to Hemingway substation in southern Idaho. This project was first proposed by PacifiCorp and Idaho Power in May 2007. In every IRP since, PacifiCorp has sought to establish a value proposition and need for the transmission segments, consistently alluding to or invoking new access to renewable energy resources.[57] Sierra Club's position on the

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[57] PacifiCorp 2008 IRP, p65: "This upsizing would potentially provide a number of local and regional benefits such as: maximizing the use of new proposed corridors*, potential to reduce environmental impacts*, provide economies of scale needed for large infrastructure, lower cost per megawatt of transport capacity made available, and improved opportunity for third parties to obtain new long-term firm transmission capacity." [Emphasis added]

PacifiCorp 2011 IRP, p286: "PacifiCorp has partnered with Idaho Power to build the Windstar to Populus project, which will improve access to existing and new generating resources, including wind, and delivery of these resources to both utilities' customers."

PacifiCorp 2013 IRP, p66: "The [Gateway West] project would enable the Company to more efficiently dispatch system resources, improve performance of the transmission system (i.e. reduced line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long-term."

PacifiCorp 2015 IRP, p50: [Same as above quote]

Gateway project has remained consistent: unless the incremental transmission into eastern Wyoming can be shown to lead definitively to new renewable energy, and PacifiCorp elects to pursue that renewable energy in a reasonable timeframe, the transmission project has not shown a ratepayer benefit. In every IRP, the Company's resource plan defers – or fails to find – any incremental renewable energy benefit, thus begging the question of why ratepayers should pay for new transmission in the region if it can only be shown to serve existing coal generators.

The 2017 IRP is the first plan to show a definitive relationship between new transmission and the ability to achieve incremental renewable energy. In this IRP, the Company tests four Gateway West ("GW") combinations as shown in Figure 10, below. These include a segment from Windstar (eastern WY) to Bridger (south-central WY) through Aeolus called Segment D, a segment from Aeolus (eastern WY) to Mona (central UT) called Segment F, a shorter sub-segment from Aeolus to Bridger ("D2"), and a combination of segments D and F. Without these incremental segments in place, the System Optimizer model selects 300 MW of new wind in eastern Wyoming ("WYAE"). With the D2 segment in place, the model selects 1,200 MW of new wind in eastern Wyoming in 2021.

*Is the transmission line necessary for the development of Wyoming wind? Not necessarily. PacifiCorp may not need **new** transmission to access these low-cost resources.*

This new line is not necessarily needed for the development of substantial new wind in Wyoming. While the key to unlocking new cost-effective renewables in Wyoming is transmission, it is not clear that PacifiCorp needs ***new*** transmission to access these low-cost resources.

Figure 10. Detail from 2017 IRP Figure 8.33 showing Gateway West segments

Currently, transmission capacity from Aeolis to Wyoming South is constrained. As a result, new, economic wind is struggling to break onto the system. According to PacifiCorp's System Optimizer, the current line operates at a very high capacity factor throughout most of the year, a function primarily due to serving coal from the Wyodak and Dave Johnston plants. Building new transmission could allow for new resources, such as economic Wyoming wind, to come online upstream of Jim Bridger. The Company's modeling shows that after building Segment D2 of Gateway West in 2021, over a gigawatt of new wind could come online, saturating the new and existing transmission lines. This aims to show that the new transmission is critical to the wind, but the fate of the Dave Johnston units tells another story.

According to the Company's modeling, when the Dave Johnston plant retires in 2028, it releases 762 MWs of transmission, which reduces the loading on the initially existing transmission lines and reduces the loading on the new D2 segment to almost nothing. As a result, the new D2 segment transmission line, purportedly critical for new renewable resources, only shows approximately seven years of apparent value – from when Segment D2 is built in 2021 to when the Dave Johnston units retire in 2028.

Confidential Figure 11 shows the capacity factors of the transmission ties from Aeolus to Bridger in the base case and the case where the new segment is constructed. In the base case (OP-NT3), the capacity factor of the [redacted] markedly with 300 MW of new wind capacity built in 2021, then [redacted] in 2028 after Dave Johnston retires. In the case where Segment D2 is constructed (GW-4), the capacity factor of the [redacted], while the [redacted] the new wind. However, after the retirement of Dave Johnston, the utilization of [redacted]. This indicates that Dave Johnston is in direct competition for valuable transmission line space.

Confidential Figure 11. Transmission tie capacity factors by scenario, Aeolus to Bridger (existing and new Segment D2)

[redacted]

The question is not whether new wind is cost-effective with new transmission, but whether retiring Dave Johnston is more cost-effective than building new transmission. Clearly, the model indicates that new Wyoming wind is cost-effective – if transmission is available to transport that wind to load centers. There are two potential mechanisms to free up transmission, build a new transmission line, or retire an existing coal plant currently utilizing the transmission line. PacifiCorp's IRP only tests the former of these scenarios, but Sierra Club can use its coal valuation assessment and data provided by PacifiCorp to roughly assess the total cost of replacing Dave Johnston with wind.

The simplest scenario upon which to base this test is case GW-4, the primary sensitivity used to assess the value of building Gateway West segment D2. PacifiCorp assesses that case at $23,159 million. The cost of the new transmission line alone is [redacted] in net present value terms. If roughly equivalent transmission were available without the cost of the new segment, Case GW-4 would cost [redacted].

Sierra Club assessed the total value of the Dave Johnston plant at about [redacted], still assuming a 2028 retirement (see Confidential Figure 11). If we were to assess the closure of Dave Johnston in 2018 as a cost, but one that allows the Wyoming wind to come online, this hypothetical case would cost about [redacted] – or less than the GW-4 case upon which the Preferred Scenario is based. This rough analysis indicates that retiring Dave Johnston is at least competitive, and likely more cost-effective, than building new transmission to harvest new wind in eastern Wyoming.

Confidential Figure 12. Estimated cost of two scenarios to acquire incremental wind: transmission, or DJ retirement

[redacted]

> *The question is not if new wind is cost-effective with new transmission, but if retiring Dave Johnston is more cost-effective than building new transmission.*
>
> *The answer? It is.*

Sierra Club supports rational and reasonable transmission initiatives that lead to cleaner, more productive and equitable grids. The Gateway West transmission segment D2 in this case does lead to new renewable energy. PacifiCorp must immediately assess the transmission and capacity expansion benefits associated with the retirement of the Dave Johnston plant between 2018 and 2021 and present its findings to the Commission in its July 2017 comments responding to staff and intervenors: Cost-effective alternatives to major capital expenditures must be disclosed prior to any capital outlay.

6. Demand-side Management Modeling

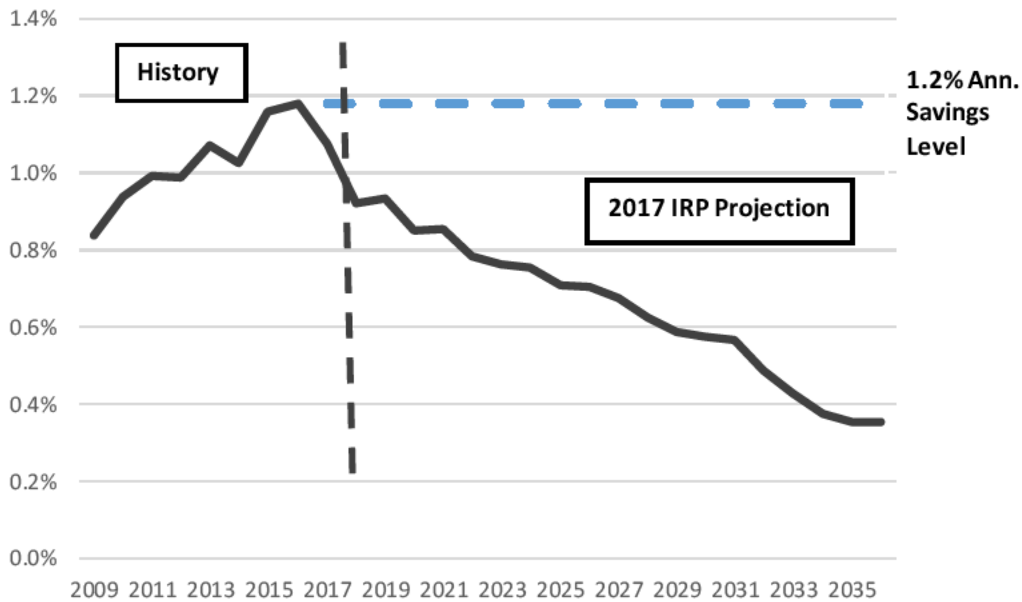
PacifiCorp's projection of energy efficiency (EE) resources (i.e., Class 2 DSM) in its 2017 IRP appear to be substantially underestimated, and depicts a bleak future for energy efficiency – a resource that has proven to be one of the largest and most cost-effective options for meeting demand over the last 35 to 40 years.[58]

The Company's projection also goes against PacifiCorp's own and the region's historical trend of expanding energy efficiency programs. Figure 13, below, presents PacifiCorp's historical and projected annual incremental energy savings from its energy efficiency programs across all of its jurisdictions. As shown in this figure, PacifiCorp kept gradually increasing annual energy savings over the past 8 years from 0.8 percent per year in 2009 to about 1.2 percent per year in 2016.[59]

[58] A 2016 study by the American Council for an Energy Efficient Economy (ACEEE) revealed that accumulated impacts of energy efficiency gains over the past 35 years are now equal to more than half of today's entire energy consumption. See this report at http://aceee.org/sites/default/files/publications/researchreports/u1604.pdf

[59] This savings estimate for 2016 does not include any savings from Wyoming as its 2016 annual report has not been released yet as of June 16, 2017.

Figure 13. PacifiCorp EE Program: History vs. 2017 IRP Projection[60]



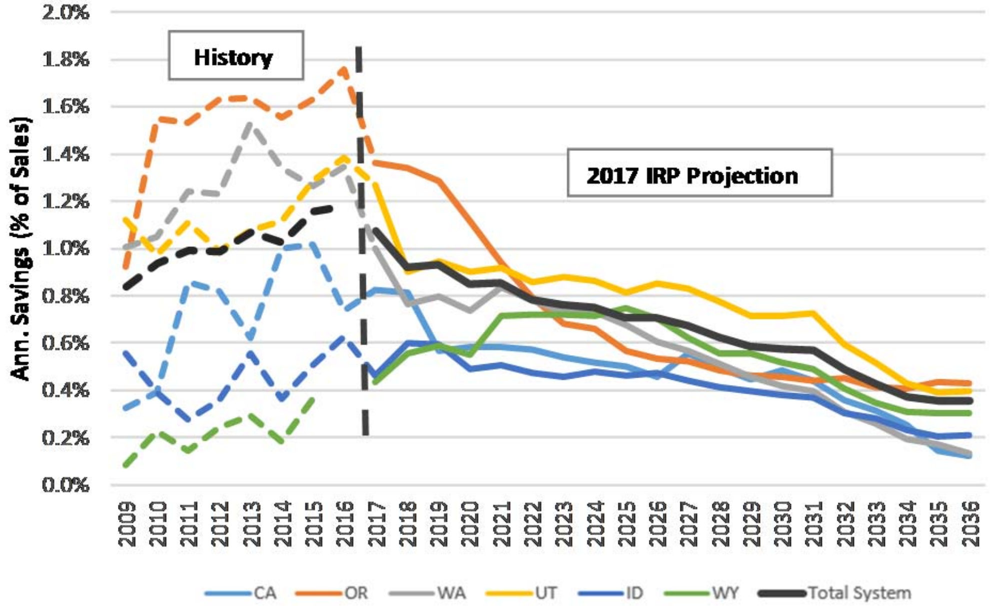
Data source: PacifiCorp 2017 IRP. Table D.4 and Table A.1; Oregon Docket LC 67, Sierra Club Data Request 1.16

Notably, while PacifiCorp has found additional energy efficiency system-wide year-on-year, the Company projects that starting this year, it will be unsuccessful in finding additional incremental programs, dropping from a modest 1.2% annual incremental savings achieved in 2016 to half that by 2025, and less than a third by 2035. Assessing actual savings and PacifiCorp's projections by jurisdiction further highlights the discontinuity between actual program accomplishments and projections as shown in Figure 14, below. PacifiCorp is projecting a substantial drop in savings in Oregon, Washington and Utah. While PacifiCorp's program in Utah had been steadily maintaining one (1) percent per year savings over six years in the past,

[60] Sales after 2026 are escalated at the annual growth rate for the first 10 years for each state. The aggregated results across all states for 2036 appear very close to the results shown in Figure 1.2 in the IRP Volume I.

and then just recently increased its annual savings to about 1.4 percent, PacifiCorp is now projecting that Utah's annual incremental energy savings drop to 0.4 percent by 2034.

Figure 14. PacifiCorp EE Program: History vs. 2017 IRP Projection by Jurisdiction

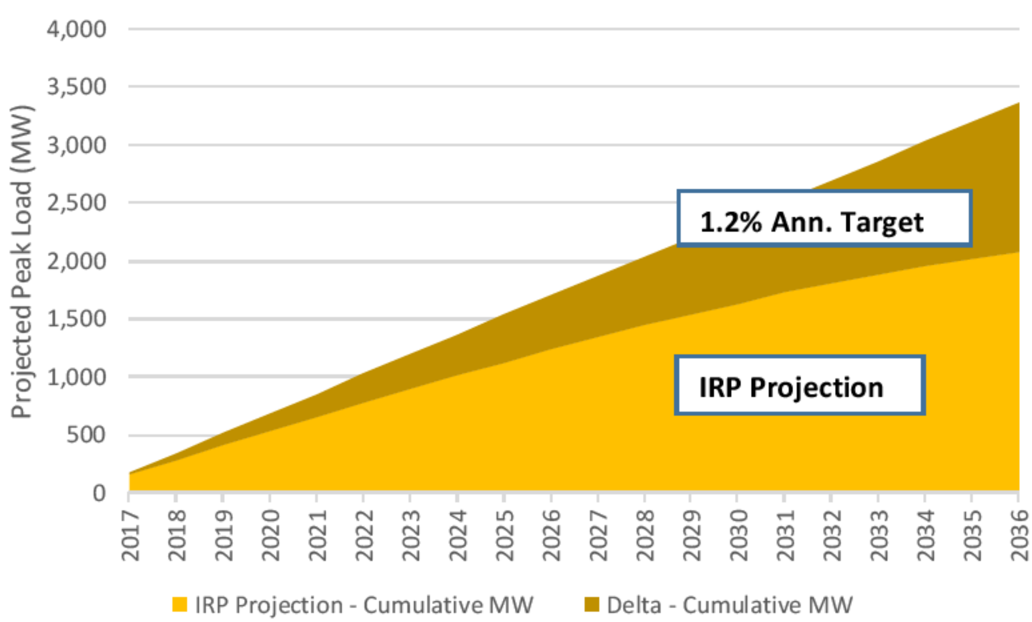


Why are PacifiCorp's projections so out of alignment with historic savings? The Company bases its projections on a potential study, which is designed to estimate achievable savings based on today's knowledge, and often currently commercially available technologies – not fully capturing long-term projections of potential savings. Potential studies are excellent tools for the focus and design of near-term efficiency programs, but do not adequately provide long-term projections.

The current savings level of 1.2 percent is the highest in history for the Company, but, importantly, this level of savings is still considerably below what leading utilities and states are achieving in the country. Setting aside potential expansion of the Company's energy efficiency efforts, PacifiCorp could simply maintain the current level of annual energy savings of about 1.2 percent per year, and reap dramatic system savings.

PacifiCorp is currently projecting to procure about 2,000 MW capacity from energy efficiency resources (or Class 2 DSM) by 2036. Our analysis shows that if the Company maintains the savings level at 1.2 percent per year, it could acquire an additional 1,280 MW capacity from energy efficiency by 2036, as shown in Figure 15, below. In fact, at 1.2% incremental energy efficiency savings, the Company could offset 250 MW of capacity requirement by 2022 (the capacity of both Hayden and Craig, combined). By 2028, the Company would have avoided an incremental 590 MW of requirement. If nothing else, efficiency offers an effective hedge against PacifiCorp's intent to continuously purchase capacity from the market.

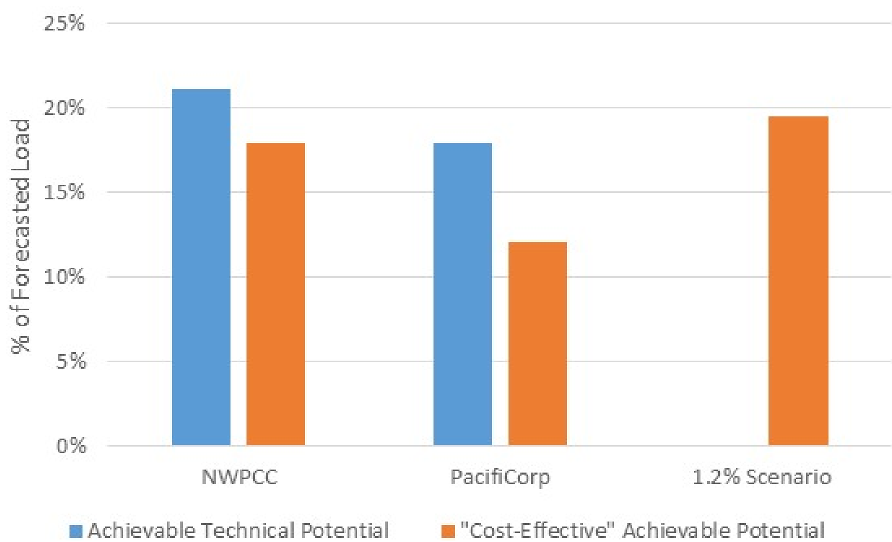
Figure 15. Capacity Savings: IRP Projection vs. 1.2% Savings Target



The current IRP projection results in just about 12 percent cumulative energy savings in 2036. In contrast, the 1.2 percent scenario results in about 19 percent energy savings relative to the projected system sales forecast in 2036. The result from the 1.2 percent scenario is more aligned with the Northwest Power Coordination Council's (NWPCC) Seventh Power Plan, which estimated about 18 percent of its load will be met with energy efficiency by 2036.

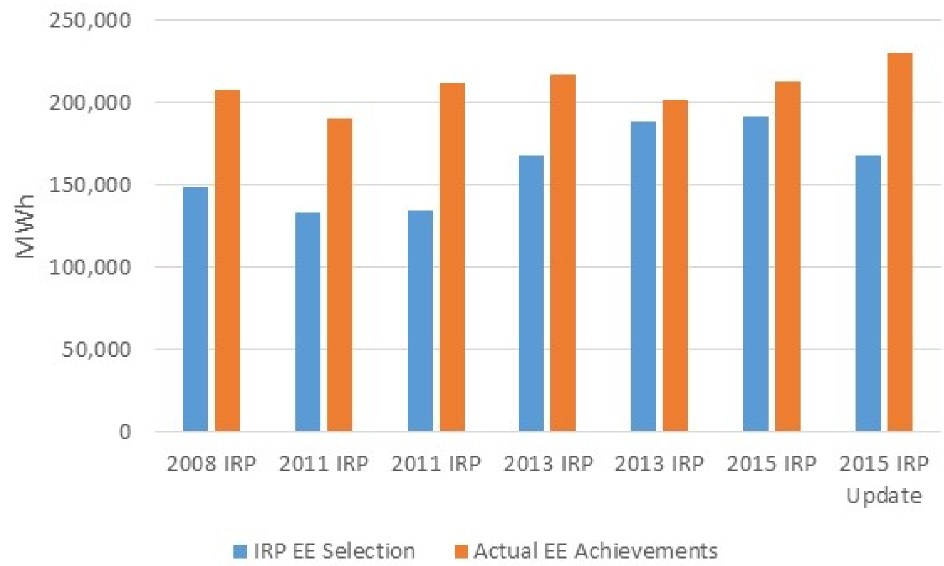
Figure 16 provides a comparison of these three savings estimates as "cost-effective" achievable potential estimates along with achievable technical potential estimates by NWPCC and PacifiCorp. This chart shows two important points. First the 1.2 percent scenario is a reasonable projection. Second, it makes it clear that NWPCC assesses both deeper technical potential savings than PacifiCorp (i.e. the pool of possible savings) and that more of those savings are likely to be cost effective than assessed by PacifiCorp. In fact, NWPCC assesses that the Northwest can cost effectively save more than PacifiCorp even believes is technically available.

Figure 16. Achievable Technical Potential and "Cost-Effective" Achievable Potential: NWPCC, PacifiCorp vs. 1.2% Scenario



There is strong evidence that PacifiCorp has underestimated cost-effective energy efficiency potential over the past several years. For example, compare actual energy efficiency achievements with the Company's past IRP results on energy efficiency selection for Oregon. As shown in Figure 17, below, PacifiCorp consistently underestimated cost-effective energy efficiency resources over the past seven years, ranging from about a 7 percent underestimation in the 2014 IRP to at or above 30 percent underestimates in 2010-2012 and 2016.

Figure 17. Historical IRP EE Resource Selection vs. Actual EE Achievements for Oregon[61]



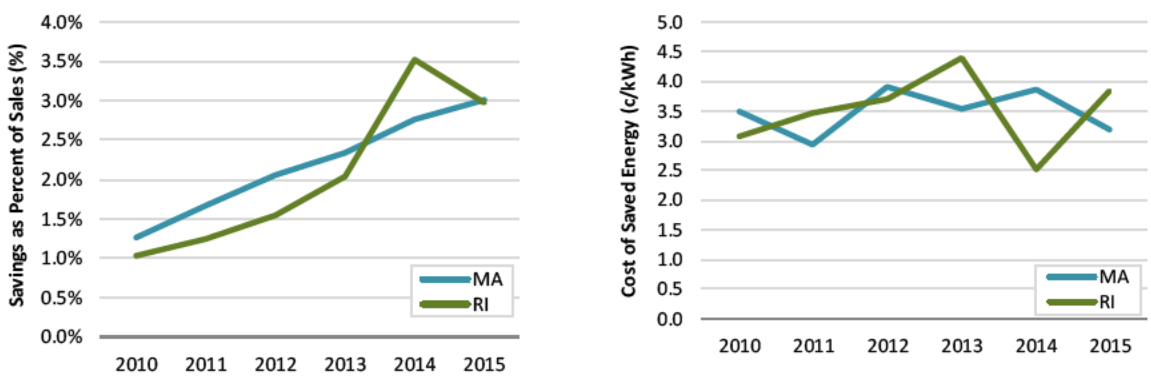
The above graph shows that PacifiCorp is consistently able to achieve more energy efficiency than it forecasted in its IRPs. Given the low level of the cost-effective achievable potential estimated by PacifiCorp, the Company's energy efficiency assumptions and screening methods have serious limitations.

[61] Sources: PacifiCorp's data response regarding its 2017 IRP in Docket LC 67 before the Public Utility Commission of Oregon, Attachment OPUC 47 and Energy Trust of Oregon (ETO): average megawatts (aMW) converted to megawatt-hours (MWh) for comparison with IRP selections.

6.1. PacifiCorp Overestimates the Cost of Energy Efficiency

PacifiCorp projects that not only will available efficiency supply become more difficult to procure, dropping quickly after 2017, but also that the cost of saved energy will increase for every new increment of energy required. Experiences in leading states show that incremental energy efficiency does not have to be expensive. In 2016, Oregon, Washington and California scored in the top 10 states for energy efficiency policies and implementation.[62] Two other top ranking states, Massachusetts and Rhode Island[63] have expanded their programs by three-fold from about a one (1) percent level in 2010 to a three (3) percent level in 2015. In the meantime, utilities in these two states have kept program costs stable at around 3 to 4 cents per kWh (See Figure 18 below). These two states are planning to maintain their annual savings around 2.5 to 3 percent per year for the next few years.

Figure 18. Massachusetts and Rhode Island Examples – Savings Achievements (left, % of annual sales) and Cost of Saved Energy (right, cents per kWh) from 2010 to 2015

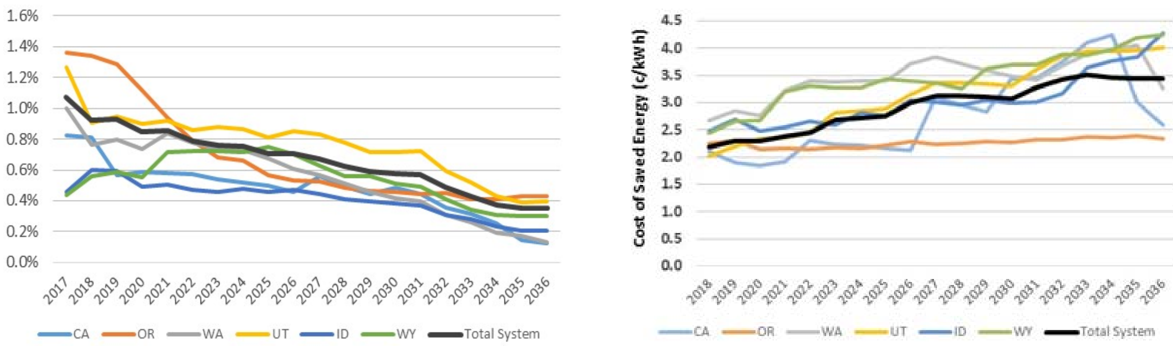


Source: Mass Save Data, available at http://masssavedata.com/Public/Home; National Grid Rhode Island "Year-End" annual program reports

[62] ACEEE 2016 Scorecard. Rankings of 7, 8 and 1, respectively for OR, WA, and CA.
[63] ACEEE 2016 Scorecard. Rankings of 1 and 4, respectively for MA and RI.

In a stark contrast to actual experience in these leading states, PacifiCorp projects a declining level of annual energy savings year by year, and yet an increasing cost of saved energy as show in Figure 19 below. Based on the experience by the leading states, PacifiCorp should be able to achieve a substantially higher amount of energy savings (e.g., over 2 percent) by spending about 3.5 cents per kWh savings – a level comparable to the cost of saved energy in the leading states, but is only projecting to achieve 0.4 percent in outer years.

Figure 19. PacifiCorp 2017 IRP Energy Efficiency – Savings Projection (left, % of annual sales) and Cost of Saved Energy (right, cents per kWh in $2016) from 2017 to 2036[64,65]



Source: "SO Portfolio (FG-GW4)" and "IRP2017 DSM2 potential-20161021 with adjustments" Excel files

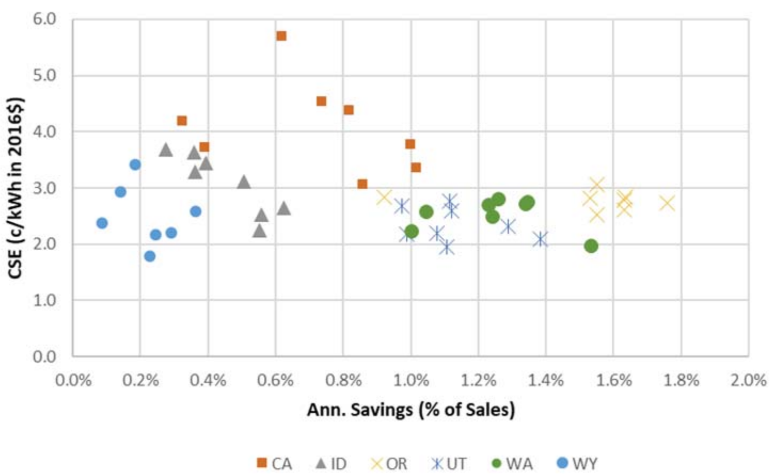
PacifiCorp's increasing cost trends and reduced energy efficiency potential are neither supported by its own experience to date. Figure 20, below presents historical program costs of saved energy

64 The weighted average annual program costs were estimated based on our review of (a) Class 2 DSM cost bundles (presented as MW reductions) selected by the SO model for each state available in "SO Portfolio (FG-GW4)" Excel file and (b) levelized costs and annual energy savings data available for each of the selected cost bundles available in "IRP2017 DSM2 potential-20161021 with adjustments" Excel file.

65 Oregon is an outlier here on the cost of saved energy because the underlying energy efficiency potential data for the state is based on an Energy Trust of Oregon (ETO) study – not PacifiCorp's AEG study. The ETO study takes into account efficiency and cost improvements over the study's forecast horizon for emerging measures. AEG, by comparison discusses baseline measure efficiency improvements, but does not actually account for improvements or cost reductions for emerging measures. For ETO's approach, see Navigant (2014). Energy Efficiency Resource Assessment Report, p. 10, available at https://www.energytrust.org/wp-content/uploads/2016/12/Energy_Efficiency__Resource_Assessment_Report.pdf

for all of PacifiCorp's jurisdictions from 2009 through 2016 (except Wyoming in 2016). A key finding is that program costs have stayed remarkably flat across jurisdictions, irrespective of the incremental annual savings level. More importantly the largest jurisdictions – Utah and Oregon – have maintained a cost of saved energy below 3¢/kWh even as annual incremental savings have risen above 1% per year.

Figure 20. PacifiCorp's Historical EE Program Performance: Cost of Saved Energy (CSE) vs. Annual Savings (2009 - 2016)[66]



Sources: Oregon Docket LC 67/PacifiCorp, June 13, 2017, Sierra Club Data Request 1.16; EIA 861 utility sales data

6.2. PacifiCorp's Energy Efficiency Screening Method has Many Serious Flaws and Limitations

PacifiCorp's energy efficiency projection is severely underestimated and unrealistically costly, both of which are not supported by any historical evidence elsewhere and even by its own experience as discussed above. The main reason for this is that PacifiCorp's energy efficiency

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[66] Levelized costs of saved energy were estimated based on a 6.66 percent weighted average cost of capital and a 10.6 average program measure life. The measure life is based on historical savings data by PacifiCorp under its Idaho jurisdiction, available at http://www.pacificorp.com/es/dsm/idaho.html.

projection is fraught with numerous serious flaws and limitations in the way energy savings potential was estimated and how the Company's System Optimizer model is set up to screen and select energy efficiency resources.

To estimate achievable "cost-effective" energy efficiency, PacifiCorp consolidated numerous energy efficiency measures from the two potential studies into 27 levelized cost bundles, adjusting the measure costs for various benefits that could not be modeled in System Optimizer. These benefits included the value of deferring transmission and distribution, the benefit of avoiding future risks, and a 10 percent "conservation adder" from NWPCC, applied only in Washington and Oregon. The suite of bundles were then allowed to "compete" in the System Optimizer model against new supply-side options and market-based power (including FOTs); those that were selected were deemed achievable cost-effective energy efficiency resources.[67]

PacifiCorp's methodology for assessing energy efficiency on the supply side is troubling and raises several related issues:[68]

- **PacifiCorp's estimated costs and achievement limits are based on technologies known and employed today and ignores future technological improvements or cost reduction**. While generally acceptable for annual program planning, the use of a potential study for long-term planning always comes with a problematic flaw, as the potential study cannot fully capture likely future technological improvements and uses. The history of energy efficiency has shown that technological advancements play a substantial role in keeping the cost of

[67] PacifiCorp IRP, p. 137.

[68] Outside of Washington state's requirement that investor-owned utilities model efficiency as a competitive resource, we are only aware of one other utility that has considered energy efficiency in this manner – Tennessee Valley Authority (see http://aceee.org/sites/default/files/pdf/conferences/eer/2015/Kenji_Takahashi_Session2D_EER15_9.21.15.pdf) TVA sought to follow PacifiCorp's methodology, ultimately identifying several substantial long-term data gaps that rendered the process less useful.

efficiency low. Recent technological leaps in LED lighting, thermostat control, heat pumps, and commercial appliances have driven down the costs – and widened the market – for efficiency measures. The outcome of PacifiCorp's method is that it assumes cost effective efficiency measures simply "run out," a fear thus unrealized even in leading states. (Details of this discussion is presented in Appendix A.)

- **Avoided costs are severely underestimated**. PacifiCorp estimates net costs of energy efficiency bundles by adding some benefits and select cost-effective energy efficiency bundles in the System Optimizer model. We found that some of the benefits included in this analysis are substantially underestimated. For example, PacifiCorp's T&D deferral credit of $13.56/kW-year is much lower than the values used by other jurisdictions, but also lower than the values the Company used to use in the past IRPs. Our own survey of T&D deferral credits of 25 cases across the country found a range of T&D credits from the lowest value of $13.56/kW-year from PacifiCorp's current IRP to $200/kW-year with an average of $81/kW-year. Impacts of using higher, more reasonable values are substantial. For example, using $80/kW-year instead of $13.56 results in an additional 74 MW of cost-effective energy efficiency from Utah alone by 2036 based on energy efficiency measure bundle data provided by the Company.[69]

- **Energy efficiency screening methods are too restrictive.** The Company's energy efficiency screening method is not only restrictive, but also goes against conventional practices in many parts of the region and country as to how energy efficiency programs are in practice evaluated for their cost-effectiveness in many parts of the region and country. First, screening energy efficiency at measure level is overly restrictive, and artificially restricting the amount of cost-effective energy efficiency "programs" or portfolio of energy efficiency programs. If energy efficiency resources are screened at program or portfolio level, considerably larger amounts of measures would be included, and the entire program, sector, or portfolio would be still cost-effective. We estimate that if the weighted average cost of the entire portfolio is regarded as a single energy efficiency bundle, Utah alone could provide about 50 percent more capacity each year, resulting in an additional 600 MW of capacity by 2036 while the portfolio wide cost is still slightly lower than the expected annual marginal cost.[70] This approach would enable utilities to experiment with different strategies and technologies that may

[69] Detailed discussions of the T&D credit as well as other benefits are provided in Appendix A.
[70] We estimated a marginal cost each year for Utah by using the highest cost of cost-effective energy efficiency bundle being selected by the SO model as a proxy. We then selected as much energy efficiency cost bundle as possible to the extent the weighted average cost of the portfolio becomes close to the marginal cost each year. The measure cost and savings data were obtained from "IRP2017 DSM2 potential-20161021 with adjustments" Excel file.

not be immediately cost-effective or require further testing, such as pilot programs, market transformation programs, or emerging technologies. In fact, the majority of states including Oregon and Utah screens energy efficiency primarily at a program or portfolio level.[71]

- **PacifiCorp does not allow energy efficiency to compete with the existing coal power plants in the System Optimizer model**. Stating that efficiency can "compete" against supply-side measures in the IRP oversells the actual implementation. In not allowing existing coal plants to retire cost effectively, PacifiCorp leaves the system in a net long position (i.e. oversupplied), thus providing little for energy efficiency to actually compete against. Instead, energy efficiency competes against market purchases, or contributes to market sales and is assumed to only have a market energy benefit at least in the first several years until new power plants are expected to be online. This framing is inconsistent with the valuation PacifiCorp provides to its existing coal resources, assuming that coal has both an energy and capacity benefit. Real competition would allow efficiency to compete against both existing and new resources.

- Finally, allowing energy efficiency to compete with supply-side resources adds substantial complication and does not illustrate the long-term value of energy efficiency investments over the span of the IRP. All the sensitivities run by the Company call for approximately the same amount of energy efficiency through the end of the analysis period, with a variance of about 8% from the highest procurement run (1,511 MW in the east with a CO2 tax) to the lowest procurement run (1,387 MW in the east with a low-demand run). This is a decidedly false precision.

Sierra Club supports PacifiCorp taking affirmative action towards the procurement of near-term efficiency as part of the IRP process and evaluation. Still, we find the use of potential studies in

[71] Michigan Public Service Commission and Michigan Energy Office (2013). Readying Michigan to Make Good Energy Decisions: Energy Efficiency, Appendix D: Energy Efficiency Cost-Effectiveness Tests, available at http://www michigan.gov/documents/energy/ee_report_441094_7.pdf; Rocky Mountain Power (2017). Utah Energy Efficiency and Peak Reduction Annual Report January 1, 2016 – December 31, 2016, available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/2016/17-035-32_UT_2016_DSM_Annual_Report_RMP_(5-15-17).pdf

the assessment of long-term efficiency trajectories problematic and understates the contribution of this resource to the system. Therefore, potential studies should not be included.[72]

7. CONCLUSION

Sierra Club respectfully requests that the Commission not acknowledge Action Items 1a (Wind Repowering) and all Action Items 5 (Coal Resource Actions). In addition, we ask that the Commission require PacifiCorp to immediately provide an economic assessment of maintaining Dave Johnston versus building new transmission before acknowledging Action Item 2a (Aeolus to Bridger/Anticline Transmission), and that such analysis be completed in parallel with the CPCN filed in Wyoming.

Dated: October 24, 2017

Respectfully submitted,

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[72] We identified other technical problems with AEG and PacifiCorp's potential study and cost estimates. These are presented in Appendix A.

APPENDIX A: ENERGY EFFICIENCY STUDY FLAWS

Flawed Energy Efficiency Potential Estimates

Our review of PacifiCorp's 2017 IRP and the AEG study found several flaws in the ways AEG and PacifiCorp screen energy efficiency resources as follows:

1) Avoided costs are underestimated
2) Energy efficiency screening method is too restrictive
3) Certain emerging measures are underrepresented
4) Energy efficiency measure costs are likely to be overestimated

Below, we present these key issues in detail except the last flaw which is explained at the end of Section 6.

Avoided costs are underestimated

PacifiCorp applies a T&D deferral credit, a stochastic risk reduction credit, and Northwest Power Act's 10 percent conservation credit to estimate a net levelized cost for each measure bundle. The original cost bundle also includes measures that contain certain non-energy benefits such as water and operation and maintenance costs depending on states. We found PacifiCorp's approach has limitations in T&D deferral credit (or avoided cost), the application of the 10 percent conservation credit, and O&M costs.

T&D deferral credit

PacifiCorp applies a T&D deferral credit of $13.56/kW-year. We found that PacifiCorp's value is substantially lower than T&D avoided costs used in other jurisdictions as well as PacifiCorp's own previous T&D avoided costs. For example, based on its review of avoided T&D costs used by utilities in the region, the NWPCC developed and is using $26 per kW-year (in 2012$ or about $27.5 in 2016$) for avoided transmission and $31 per kW-year for avoided distribution (in

2012$ or about $33 in 2016$), totaling $57 per kW-year (in 2012$) in the Seventh Power Plan.[73] Interestingly the original survey that is presented in the NWPCC's Sixth Power Plan included PacifiCorp for which the T&D avoided costs were $104/kW-year in 2006$ (or $122/kWh in 2016$). We also found out PacifiCorp's 2013 IRP and the 2015 IRP used $54/kW-year for a T&D investment deferral value.[74] Further we found that PacifiCorp's 2017 T&D value is the lowest value among numerous utility T&D values based on our literature review of avoided T&D costs across the country (including the NWPCC's avoided T&D cost survey) as shown in Figure 21 below. T&D avoided costs from all samples range from $20 to $200 per kW with an average of about $80 per kW-year.

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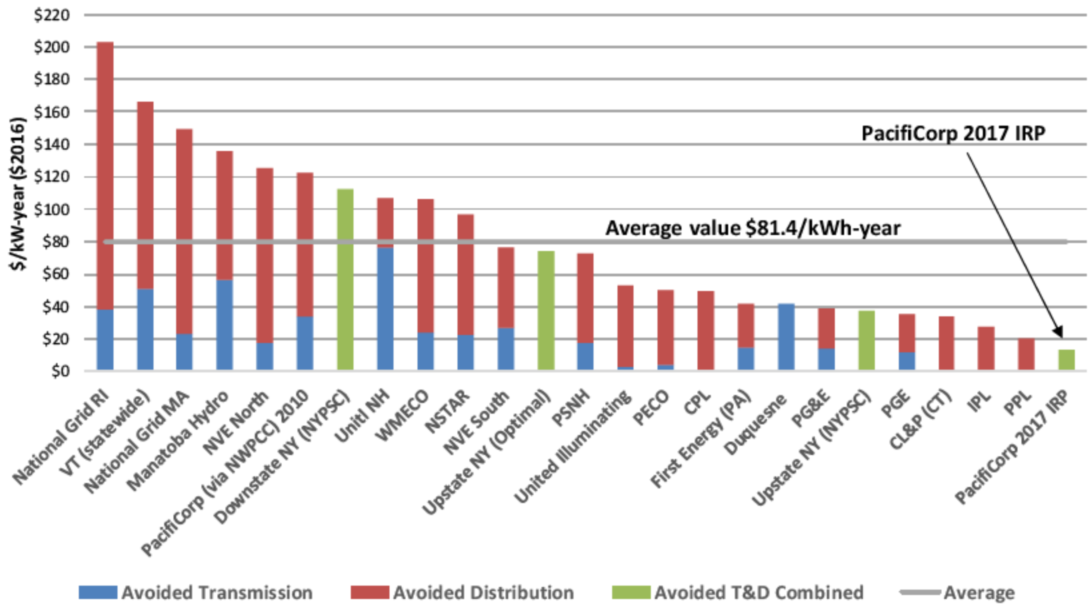
[73] NWPCC (2016). Seventh Power Plan, Appendix G; NWPCC (2010). Sixth Power Plan, Appendix E.
[74] PacifiCorp (2013) 2013 Integrated Resource Plan, Volume 1, p. 147, available at https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol1-Main_4-30-13.pdf; PacifiCorp (2015) 2015 Integrated Resource Plan, Volume 1, p. 124, available at https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol1-Main_4-30-13.pdf

Figure 21. Summary of Avoided Transmission and Distribution Costs at various utilities.[75]



The current assumption of $13.56 per kW-year can be translated to $3.3 per MWh ($2016) using PacifiCorp's own load factor for energy efficiency measures.[76] If NWPCC's T&D value is used instead, the T&D value would be increased by 4.5 folds and be about $14.5 per MWh ($2016).

10 percent conservation credit

Complying with the Northwest Power Act of 1994, the NWPCC has been applying a 10 percent cost advantage over sources of electric generation to energy efficiency and conservation

[75] Developed based on the following data sources: Hornby, R., et. al. (2015). Avoided Energy Supply Costs in New England: 2015 Report, Appendix G-1. March 27, 2015; NPWCC (2010). Sixth Northwest Conservation and Electric Power Plan, Appendix E. Northwest Power and Conservation Council. February 2010; Interstate Power and Light Company (2012). 2014-2018 EE Plan; GDS Associates et al. (2015). Demand Response Potential Pennsylvania. Pg. 4 February 2015; Acadia Consulting Group (2015). Draft Report on Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers. February 27, 2015, page 121; E3 (2014). Nevada Net Energy Metering Impacts Evaluation, July 2014; New York PSC (2009). Order Approving "Fast Track" Utility-Administered Electric Energy Efficiency Programs with Modifications, January 16, 2009; "Optimal Energy (2008). Economic Energy Efficiency Potential New York Service Territory; PacifiCorp (2017). 2017 Integrated Resource Plan – Volume I.

[76] The average EE load factor is 47 percent based on the projected MWh and MW EE reduction from "SO Portfolio (FS-GW4)" Excel workbook.

resources. However, when PacifiCorp screened energy efficiency resources, this Northwest Power Act 10 percent conservation credit is only applied to Oregon and Washington.[77] Given California, Idaho, and Wyoming use the Total Resource Cost (TRC) as a primary test, which is supposed to value costs and benefits from both the utility and customer perspectives, it is appropriate to apply either an equivalent "conservation credit" or other non-energy benefit calculation to these other states as well. In fact, most investor owned utilities in Idaho use the 10 percent credit when calculating the cost-effectiveness of all energy efficiency programs.[78] Based on our calculation, the 10 percent credit results in about $2.77 per MWh ($2016).[79] If the NWPCC's T&D deferral value is used, the 10 percent credit would result in about $3.9 per MWh ($2016).

Non-energy benefits

Non-energy benefits and secondary fuel impacts are a key component of the TRC test, but are not included for California and Wyoming.[80] But even for Oregon and Washington, it is possible that non-energy benefits just represent water savings and maintenance labor only given the AEG study refers to NWPCC's database on non-energy benefits, and NWPCC's current DSM

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[77] PacifiCorp 2017 IRP, p. 137.

[78] Idaho Power Company (2016) Demand-Side Management 2015 Annual Report – Supplement 1: Cost-Effectiveness, p. 4 – 5, available at https://www.idahopower.com/pdfs/AboutUs/RatesRegulatory/Reports/DSM_2015Supplement1.pdf

[79] Using the original T&D deferral value of $13.56 per kW-year and the average market price value of $24.39 per MWh. This value is an average forward market price for 2017 at Mid-Columbia based on "1016_OFPC_with East_West_Gas" file.

[80] AEG (2016). p. 2-9.

screening approach seems to just include water savings and maintenance labor savings.[81] Other types of non-energy benefits (e.g., s, improved comfort, improved health and safety, increased worker and student productivity, and reduced termination and reconnection fees) are real and some jurisdictions quantified such benefits.[82] Adjusting these key points would increase cost-effective energy efficiency potential for all the states, but more so for California, Idaho, and Wyoming.

CO_2 credit

The 2016 IRP effectively does not incorporate the CO_2 benefit of energy efficiency cost bundles. We found this approach non-comprehensive and inconsistent the way the Company treats CO_2 as a monetized cost in the wind and transmission projects in contemporaneous docket 17-035-40. In 17-035-40, the Company provided two projections of CO_2 prices – the Medium and High cases. In the Medium case, the CO_2 price starts around \$3 per ton in 2025 and increases to about \$8 per ton by 2036 (in \$2016). In the High case, the CO_2 prices starts around \$4 per ton in 2025 and increase to \$25 per ton by 2036 (in \$2016). These price ranges are translated into \$2 to \$4/kWh for the Medium case, and \$2 to \$11/kWh for the High case, using a typical heat rate of 7900 btu/kWh for a natural gas generator. We would expect these prices to be reflected in the selection of cost effective energy efficiency, which it was not.

[81] NWPCC (2009). "Council Conservation Resource Potential Assessment and Cost-Effectiveness Methodology", Slide 46, https://www nwcouncil.org/media/112474/Methodology.pdf
[82] See Synapse Energy Economics (2013). Energy Efficiency Cost-Effectiveness Screening in the Northeast and Mid-Atlantic States, available at http://www neep.org/sites/default/files/resources/EMV_Forum_C-E-Testing_Report_Synapse_2013%2010%2002%20Final.pdf and Erin Malone (2014). "Driving Efficiency with Non-Energy Benefits", presentation at ACEEE National Symposium on Market Transformation Conference, available at http://www.synapse-energy.com/sites/default/files/SynapsePresentation.2014-04.0.Driving-Efficiency.S0093.pdf

Certain emerging measures are underrepresented or not included

There may be some measures adopted by NWPCC that are not included in PacifiCorp's studies or that have greater per-unit savings than assumed by PacifiCorp's studies. Given the sheer amount of measure numbers, our assessment did not investigate this area in detail. However, we found one critical limitation in AEG's study assumption that it did not include any savings from conservation voltage reduction (CVR) measures. In contrast, NWPCC includes CVR and estimates its savings which accounts for about 1 percent of NWPCC's projected load.[83]

[83] NWPCC (2016). Table G – 9.

STATE OF UTAH

Public Service Commission

In the Matter of PacifiCorp's 2017 Integrated Resource Plan	Docket No. 17-035-16

CERTIFICATE OF SERVICE

I CERTIFY that on October 24, 2017, a true and correct copy of the foregoing Sierra Club Comments was served upon the following party representatives via electronic mail.

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Dated this 24th day of October, 2017 at Oakland, CA.

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