BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 62

In the Matter of PacifiCorp's 2015 Integrated Resource Plan	SIERRA CLUB'S COMMENTS ON PACIFICORP'S 2015 IRP

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I. INTRODUCTION

Sierra Club provides the following comments on PacifiCorp's 2015 integrated resource plan (IRP). In this proceeding, Sierra Club took the extraordinary step of tasking its technical experts, Synapse Energy Economics, to license and run the company's own model, System Optimizer, to independently conduct production cost modeling to determine least cost planning for PacifiCorp's 2015 IRP. The results of this independent analysis revealed a number of planning flaws that, unless remedied, could result in avoidable cost increases for customers. Our System Optimizer modeling results are described in the attached report.

Based on this independent modeling and review of the overall plan, Sierra Club's comments focus on the company's treatment of: (1) EPA's Clean Power Plan; (2) "endogenous" coal plant retirements; (3) the company's projected energy savings from energy efficiency programs and measures, and (4) energy storage technology. The Synapse report attached to the bottom of these comments provides detailed analyses on the first two items above, the Clean Power Plan and modeled coal plant retirements, while energy efficiency and energy storage are addressed in Sections II and III below.

PacifiCorp's 2015 IRP differs from past plans in important ways: **First**, the IRP included modeling of EPA's new requirement that states reduce carbon dioxide emissions from existing power plants. EPA issued the final Clean Power Plan (CPP) on August 3, 2015. PacifiCorp centered its IRP on modeling EPA's draft plan; however, the final CPP is starkly different from the original proposal. As a result, the IRP's focus on one narrow compliance mechanism, rate-based emission targets, resulted in a plan that is at odds with the final CPP, is opaque and unnecessarily complex, and runs afoul of long-established least-cost planning practices.

Second, PacifiCorp put its thumb on the scale in selecting coal plant retirement options for its preferred portfolio. Rather than letting the model choose to retire units based on cost effectiveness, the company simply pre-programmed a retirement schedule into the model. These restrictions eliminated the opportunity for the model to choose the lowest cost method of complying with existing and future environmental requirements. PacifiCorp's coal fleet continues to face a variety of new environmental regulations that impose costs and operating restrictions. Since 2008, PacifiCorp has made significant capital and operating expenditures to comply with both regional haze and the mercury and air toxics standards (MATS) rules. Going forward, PacifiCorp's coal units will face additional regional haze costs, and may face new National Ambient Air Quality Standards (NAAQS), as well as a coal combustion residual (CCR) rule, and CO_2 emissions reductions under the CPP. It is incumbent upon the company to explore and disclose to regulators and customers viable alternative compliance options to address the simple fact that the company's continued reliance on coal-fired power is increasingly risky and expensive.

Finally, as shown below, the IRP underestimated the amount of energy the company could save through energy efficiency programs throughout its service territory, and its rudimentary treatment of energy storage has remained unchanged since 2008.

II. ENERGY EFFICIENCY

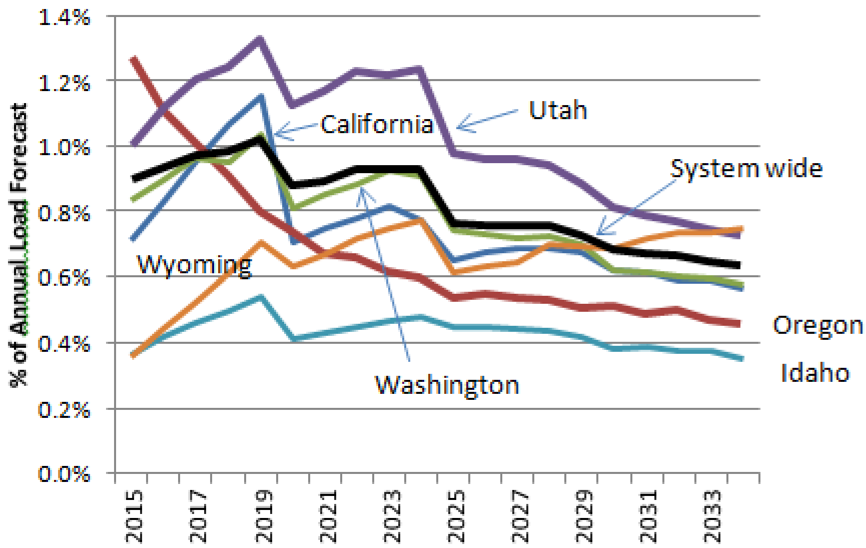
A. The IRP Significantly Underestimated Energy Efficiency Potential in its Service Territory

The projection of annual incremental energy savings in PacifiCorp's 2015 IRP is overly conservative, and significantly lower than what leading states and utilities have achieved in the past or are planning to achieve in the near future. For the 2015 IRP, the projected annual savings significantly decrease year by year. This outcome is largely influenced by a major inherent limitation of potential studies because potential studies primarily rely on current commercially available technologies and lack information on savings from future efficiency measures. This is particularly problematic when potential studies are applied to a long-term system planning that expands beyond a 10-year horizon. Therefore it is highly likely PacifiCorp's own savings projection over the 20-year study period in its IRP is significantly underestimated.

B. Annual Incremental Savings Remain Well Below Leading States, and Falling

The IRP's projected annual incremental energy savings has flaws in the maximum annual incremental savings and annual energy savings ramp-rates. The highest savings in terms of savings as a percent of sales are around 1.3 percent (for California and Oregon); other states are far lower. These ramp rates are significantly lower than the level of savings demonstrated or targeted by leading states and utilities, as shown below. Further, all states except Wyoming are projected to reach the highest annual savings (in percent of sales) in very early years (e.g., Oregon in 2015, and the rest of states except Wyoming in 2019), and then show declines in savings. These declines are particularly significant for Oregon, Utah, and Washington (Figure 1). The annual incremental weighted average savings across all jurisdictions decrease from about 0.9 percent to about 0.6 percent by 2034.

Figure 1. Annual Incremental Energy Savings for the Preferred Portfolio (% of Annual Load Forecast)



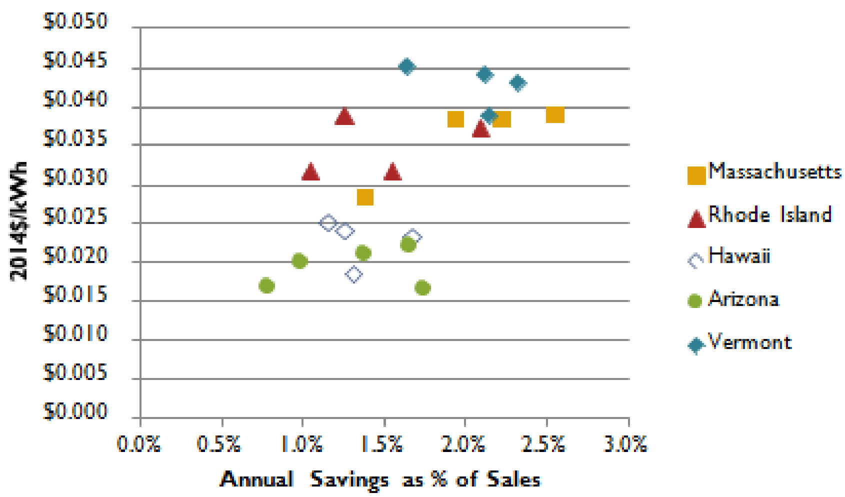
Source: PacifiCorp 2015 IRP, Volume 1, Table A.1 – Forecasted Annual Load Growth, 2015 through 2024 (Megawatt-hours); "C05a-3Q, Preferred Portfolio" worksheet in "265338Web - Copy of PacifiCorp-2015IRP_RH1-SOReportPackage-03162015 3-31-2015" file provided by PacifiCorp in OR LC-62

C. Annual Ramp Rate for New EE is Slower Than Expected, or Negative

Figure 1 also shows that all jurisdictions are expected to ramp-up annual savings by just 0.1 percent (for California) or less. Oregon has no ramp-up in savings at all, and instead its savings are expected to continue declining from the second year.

Current state policies and historical data suggest that PacifiCorp could assume a much faster ramp rate and reach a higher annual maximum savings level than what it modeled energy efficiency in the IRP. For example, several leading states have achieved a significant amount of savings cost-effectively beyond 1.5 percent to 2.5 percent levels as shown in Figure 2. It is particularly notable that Massachusetts and Vermont have been operating their energy efficiency programs for the past few decades and recently achieved 2 percent to 2.5 percent savings over multiple years at a cost of 4.5 cents per kWh or less.

Figure 2. Energy Efficiency Cost of Saved Energy ($/kWh) and Annual Savings (% of Sales) from 2009 to 2014



Sources: (1) Molina. (2014). The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs, ACEEE (2) ACEEE State Energy Efficiency Scorecard reports in 2011, 2012, and 2013. (2) Geller, et al. (2014). Maintaining High Levels of Energy Savings from Utility Energy Efficiency Programs: Strategies from the Southwest. (3) Hawaii Energy Annual Reports in 2012 to 2014 National Grid Electric and Gas Energy Efficiency Programs Year-End reports in 2010 to 2013. (4) Massachusetts program administrators' data obtained from Jeff Loiter, a member of the Massachusetts Energy Efficiency Advisory Council consultant team on April 2, 2015.

In addition, according to EPA's review of historical energy efficiency programs from 2003 to 2012 as part of the Clean Power Plan, there were 26 entities that achieved around 2 percent annual savings for the past several years. The same analysis also found that about 75 entities across the nation took just about 3 years to increase annual incremental energy savings by 1 percent, which equates to annual average ramp rates of 0.33 percent. Table 1 presents these findings broken out into two groups: Top Saver 1%, which achieved maximum first-year savings of 0.8 to 1.5 percent, and Top Saver 2%, which achieved maximum first-year savings of above 1.5 to 3 percent. Based on these results, EPA chose 0.2 percent per year as an annual savings ramp rate for each state to adopt for the purpose of complying with the Clean Power Plan.

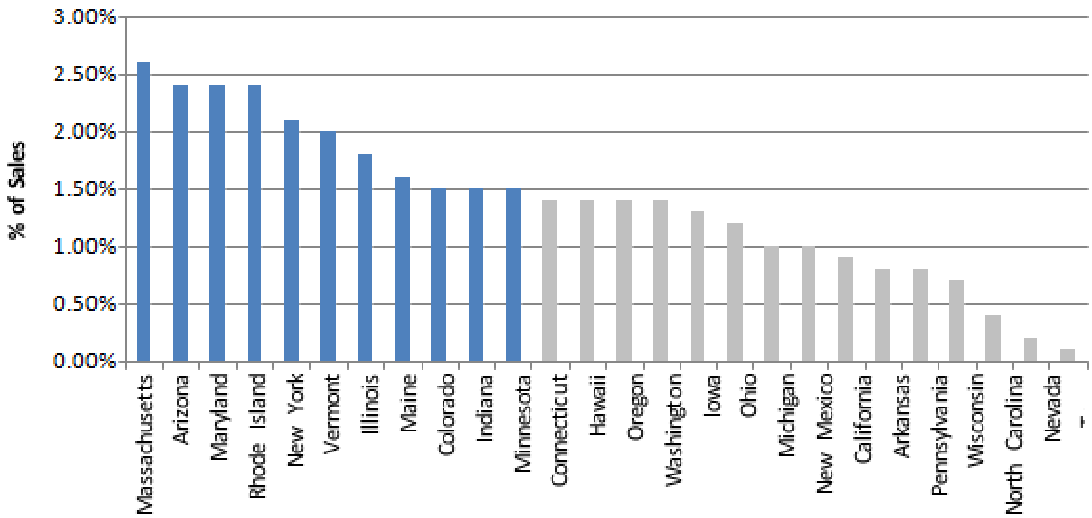
Table 1. Energy Savings Ramp-up Trends in 2003 through 2012

	Top Saver 1%		**Top Saver 2%**	
	Average Annual Savings Increase	**Estimated Years to Gain Incremental 1%**	**Average Annual Savings Increase**	**Estimated Years to Gain Incremental 1%**
Average	**0.30%**	**3.4**	**0.38%**	**2.6**
Median	**0.29%**	**3.4**	**0.34%**	**3.0**
Max	0.63%	1.6	1.28%	0.8
Min	0.10%	10	0.14%	7.3
# of sample entities	47		26	

Source: U.S. EPA. (2014). GHG Abatement Measures, Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants. Appendix 5-2.

Finally, several states with energy efficiency resource standards (EERS) have annual energy savings targets beyond the level PacifiCorp expects to achieve through its IRP. Currently about 26 states have EERS policies. Among them, 11 states have targets to achieve 1.5 percent to about 2.5 percent per year savings (Figure 3).

Figure 3. Average Incremental Energy Savings Target by State through EERS Policy



Sources: Downs et al. (2014) Energy Efficiency Resource Standards: A New Progress Report on State Experience. ACEEE

In addition, EPA found that the 10 states with annual ramp-up schedules mandated in their EERS expect annual savings at a pace ranging from 0.11 percent (Colorado and Oregon) to 0.40 percent (Rhode Island), with an average of 0.21 percent per year – twice faster than the maximum annual rate among all jurisdictions assumed by PacifiCorp.[1]

PacifiCorp should accelerate energy efficiency programs in the near term to capture cost-effective savings illustrated in the potential study. As these programs are accelerated, PacifiCorp will begin to see other cost-effective measures emerge.

D. Long-Term Energy Efficiency Potential is Rising, Not Falling

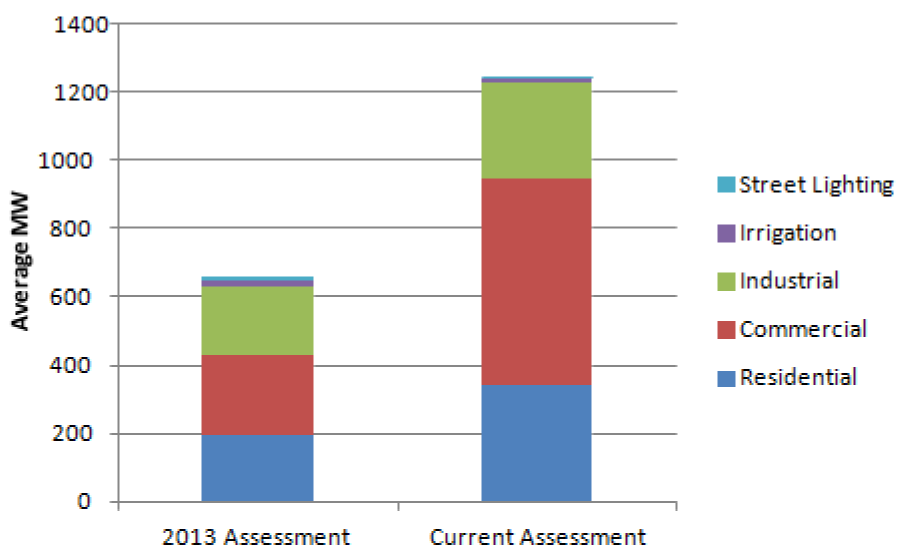
Energy efficiency potential studies have a critical, inherent limitation, especially when they are applied to project a long-term energy resource vision that goes beyond a 10-year analysis horizon. These studies rely mainly on currently commercially available technologies to estimate savings potential, and are typically designed to look at near-term savings potential. While some studies include emerging technologies and may even include expected price

[1] U.S. EPA. (2014). GHG Abatement Measures, Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants. Appendix 5-2.

reduction for certain measures, few studies attempt to estimate energy savings potential from future emerging measures that could become available in 10 to 15 years due to lack of information. The implication of this limitation is that efficiency potential studies almost always underestimate the amount of long-term savings potential. The fact that PacifiCorp's IRP presents declining available savings at a greater rate year by year is a result of this inherent limitation of potential studies.

A review of historical potential studies demonstrates consistent underestimation of energy savings potential. A case in point is PacifiCorp's own historical potential studies conducted in 2013 and in 2015. The 2015 potential study, conducted by the Applied Energy Group (AEG) for PacifiCorp, found nearly twice as much savings potential as in the 2013 study as shown in Figure 6 below despite the fact that PacifiCorp achieved additional savings since 2013. The 2015 AEG study indicates that the majority of this increase in savings is "primarily driven by the emergence of LED lighting technology as a viable, cost-effective, and rapidly improving technology option."[2]

Figure 4. Comparison of Class 2 DSM Potential with Previous Assessments

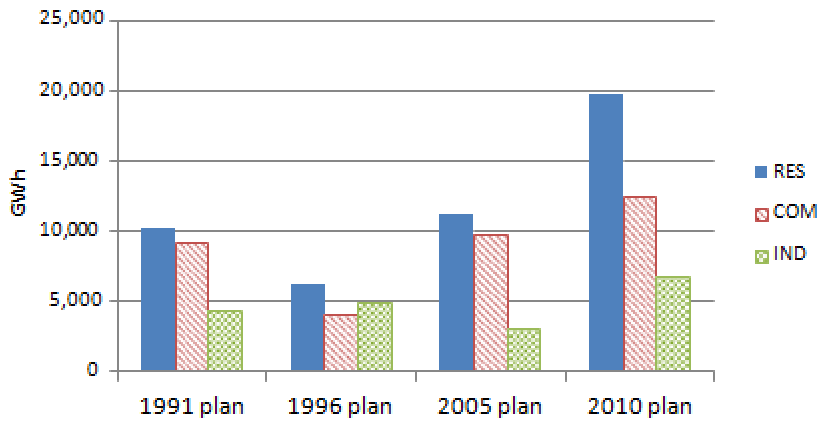


Source: AEG (2015). PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034, Volume 2. Table 5-1.

[2] AEG (2015). PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034, Volume 2. Class 2 DSM Analysis, page 5-2.

Comparing historical energy efficiency potential studies by the Northwest Power Conservation Council (NWPCC), which has a long history of running efficiency programs in the Pacific Northwest region, shows a similar pattern (see Figure 5). While the potential study for the 1996 Power Plan was lower than the previous study, the following studies in 2005 and 2010 found a greater amount of savings potential. One study reviewing these NWPCC's studies concluded that "when programs invest in higher levels of efficiency, this helps drive measurement improvement and technical innovation, resulting in large and more reliable conservation supply estimates."[3]

Figure 5. Comparison of Energy Efficiency Potential Estimates for Pacific Northwest by NWPCC's Historical Regional Power Plans (GWh)



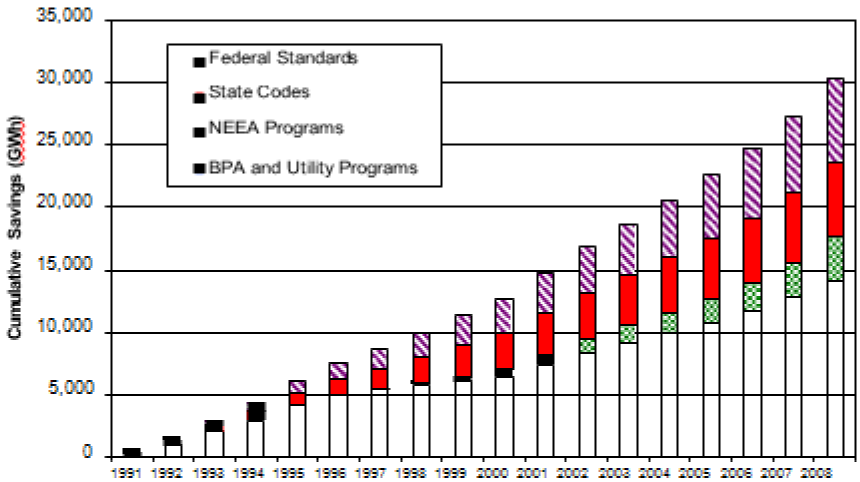
Sources: Gordon et al. 2008. "Beyond Supply Curves" Proceedings of 2008 ACEEE Summer Study on Energy Efficiency in Buildings; NWPCC 2010. Sixth Northwest Conservation and Electric Power Plan.

Figure 6 below presents historical energy savings through various energy efficiency programs and policies in the Pacific Northwest region. Significantly, the region's cumulative savings of roughly 30,000 GWh energy savings since 1991 is far more than the energy efficiency potential estimates made in the NWPCC's 1991 power plan (approximately 23,000 GWh). The latest power plan in 2010 has found even greater energy savings potential than the potential found in 1991. This historical data shows that the best strategy for making use of study results of energy efficiency potential is to try to achieve as much identified energy

[3] Gordon et al. 2008. "Beyond Supply Curves" Proceedings of 2008 ACEEE Summer Study on Energy Efficiency in Buildings, available at http://aceee.org/files/proceedings/2008/data/papers/8_419.pdf.

savings as possible in early years by following industry best practices and achievements by leading entities (e.g., reaching 2 percent per year savings by a certain year in the first 10-year horizon).

Figure 6. Cumulative Energy Efficiency Savings Estimates in the Pacific Northwest Region since 1991 (GWh)



Source: Eckrman 2010. "Regional Conservation Summary 1978 - 2008 Adjusted for BPA co-funding and including line losses" data file obtained from Tom Eckman on March 1, 2010. Average MW figures have been converted to GWh in this figure.

Based on the foregoing, PacifiCorp must appreciate that simply because a potential study recognizes today's limited technologies, the saturation of those technologies cannot mean that energy efficiency will cease to exist a decade from now. New products and services are developed at a rapid pace, and can be expected to impact PacifiCorp's system not only in the next decade but in the latter half of the study as well. It is important that PacifiCorp recognize long-term new cost effective potential, as the long-term requirements of the utility influence the decisions made by PacifiCorp today.

III. ENERGY STORAGE

A. The 2015 IRP Continued to Marginalize Energy Storage

Going back to 2008, PacifiCorp's IRPs have superficially mentioned energy storage as a potential resource worth exploring.[4] But now in 2015, the company still has not progressed beyond an incomplete and inaccurate analysis of this important emerging technology.[5] It certainly has not "proceed[ed] with an energy storage demonstration project, subject to Utah Commission approval" as promised in 2013.[6] Sierra Club was optimistic that the company might finally develop a rigorous and up-to-date analysis of energy storage within the PacifiCorp system given the outstanding storage conference the commission and other agencies hosted in 2014. But even after that informative event, the company still does not take this technology seriously and has no intention of moving forward with storage within the 20-year planning period.

The following comments on energy storage technology begin with a storage overview followed by Sierra Club's IRP-specific comments. The storage comments were prepared with the help of Chris Edgette. Chris has over a decade of experience in renewable energy strategy, policy, product development, and construction. For the last several years, Chris has specialized in market policy, application, strategy, and value proposition analysis for energy storage resources.

B. Overview: What is Energy Storage, and How Can it Benefit PacifiCorp's Service Territory?

The term "energy storage" encompasses a wide variety of technologies that can capture, store, and release energy. Energy storage technologies are diverse, including mechanical, electrochemical, and thermal technology options with each providing different advantages in terms of economic, societal, and environmental benefits.

[4] "Energy storage systems continue to be of interest, and advanced large batteries (1 MW) have been reviewed as well as traditional pumped hydro and compressed air energy storage." 2008 IRP at p.97.
[5] "A consultant study was initiated in 2011 on incremental capacity value and ancillary service benefits of energy storage. HDR Engineering (HDR) was retained by PacifiCorp to perform an Energy Storage Study to evaluate a portfolio of energy storage options." 2013 IRP at p.254.
[6] 2013 IRP Action Plan, p. 253.

Historically, much of the electricity grid has been built to operate in real time. When electricity is needed in a home, for instance, an electricity generator must increase its output to provide that electricity. Fossil generators and many hydro resources are able to vary their output on demand, so the grid is able to account for variation in customer load.

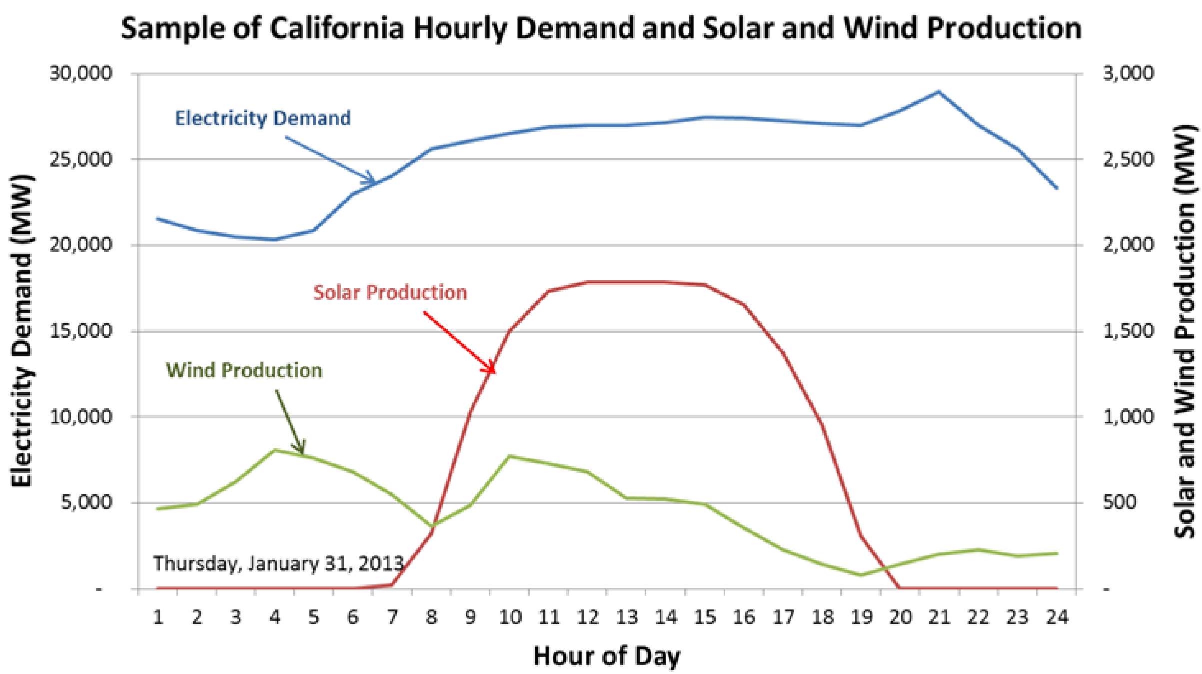
In the move beyond fossil fuels, energy storage provides a way to match customer load with generation. Some of the best and most cost effective renewable energy resources, such as wind and solar, only produce power when the wind blows or the sun shines. Energy storage can allow utilities to store renewable energy when it is most abundant, and then use the energy later to offset dirtier sources of generation.

The benefits of energy storage do not end there. Energy storage technologies provide other advantages over traditional grid resources. Storage can be very compact and does not produce local emissions so that storage can be sited where it provides the greatest benefit, such as within cities or at individual homes or businesses. Energy storage resources can be distributed throughout the grid to provide benefits at the location where it is needed most, supporting customers in their home, providing grid services at a substation, improving the output of a renewable generator, and even reducing the fuel consumption of a fossil generator.

Most energy storage technologies can react very quickly to grid variations—much more quickly than gas turbines or coal plants. This means that fewer megawatts of energy storage resources are needed to provide grid services than would be required from conventional power plants. In addition, energy storage can be configured to provide emergency backup to the grid, without relying on traditional technologies like diesel generators for reliability. Energy storage can provide many benefits with the same resource by quickly varying charge and discharge. One energy storage resource can, for instance, help smooth renewables, provide emergency backup, and reduce fossil fuel consumption, while reducing transmission and distribution infrastructure.

1. The Need to Deploy Storage Technology is Gaining Urgency

Multiple factors are contributing to the increased benefit of energy storage in today's electric power system. The need to increase renewable adoption is certainly critical. Without storage, utilities cannot sharply ramp up renewable resources. The following figure demonstrates the difference between wind and solar output and customer consumption of electricity:



While careful curtailment of renewables can help smooth their output, it is clear that storage is needed to get to a high renewable grid. Even at lower renewable penetrations, storage can provide great benefits. Currently in California, fossil generators are utilized to provide backup for intermittent renewables. In many cases, these fossil units are operated inefficiently in order to manage renewable variability, further reducing the environmental benefit of those renewables. Storage can help balance the difference between renewable output and load without relying on inefficient peaking power plants.

Energy storage system costs are falling dramatically, and cost reductions are expected to continue as the deployment of energy storage systems accelerates. The scaling effect is similar to the cost reductions in many new technologies, including wind and solar over the last decade. Scale, driven partly by electric vehicle adoption, is also resulting in improvements to the technologies themselves, as they are made more efficient, more compact, and more customer-focused. Recent cost reduction means that in certain regions, renewables balanced with solar are already more cost effective than fossil resources, even without considering climate effects.

Another key driver is the onset of smart grid controls and distributed energy resource platforms, which are allowing for increased local generation within traditional power grids. These movements should be encouraged, as smarter, customer-focused grids fueled by local renewables can be cleaner, more efficient, and more reliable than traditional grids. Energy storage is a key ingredient to creating these grids.

Finally, as more fossil fuel generation is built, the more difficult it becomes to move toward renewables. Gas generators are being installed at a rapid clip. While energy efficiency has reduced demand in some locations, electric vehicles will be increasing the need for clean electricity. The generation that utilities procure today become immediate sunk costs; those existing generators will be used in future planning proceedings as a barrier to adding renewables. The result is a society increasingly dependent on fossil generation. Procurement of energy storage, on the other hand, will satisfy many needs provided by fossil generators now, while providing an even greater benefit as grid renewable generation increases.

2. Energy Storage Technology Classes

Grid-connected energy storage covers a broad range of technology classes suited for overlapping applications needs. Most technologies can be categorized into the following general types:

- Mechanical
- Electrochemical
- Thermal

Common Energy Storage Technology Environmental Impacts

	Technology Class	Pros	Cons
Mechanical Storage	Pumped Hydropower Storage	• Low embodied energy for large energy shifting – suitable for high renewable penetrations • No toxic chemicals • Well sited projects will not obstruct natural waterways or habitats • Well sited projects can actually reduce transmission requirements.	• Water consumption due to evaporation and leakage. This can be minimized by capping ponds. • Poorly sited projects can cause significant environmental impacts • Poorly sited projects may require significant transmission additions • Potential concrete usage
	Flywheels	• No significant toxic chemicals	• Carbon fiber in some flywheels

		• Most components can be recycled/downcycled	may be energy intensive and only able to be downcycled • High energy cost on a kWh basis
	Large Scale Compressed Air	• Low embodied energy for large energy shifting • No toxic chemicals • Can balance long durations of energy – suitable for high renewable penetrations	• Requires large natural salt caverns • Siting requires transmission connection • Requires siting with natural gas plants for thermodynamic efficiency
	Small Scale Compressed Air	• No toxic chemicals • Can balance long durations of energy	• May require siting with natural gas plants for thermodynamic efficiency
	Gravitational (i.e. gravel and trains)	• No toxic chemicals • Can balance long durations of energy	• Depends on project siting
Electrochemical Storage	Lead Acid Batteries	• Highly recyclable - one of the world's best recycling programs • Sealed lead and acid are highly used in data centers and generally safe	• Lead mining may cause issues • Short lifetime – 2-5 years, typically • Energy intense per kWh
	Lithium Ion Batteries	• Potentially recyclable, but not typically cost effective • Constantly improving energy density and material utilization • Density minimizes footprint • High efficiency (85%+)	• Lithium/Phosphate/Titanate mining • Fire risk
	Flow Batteries	• Most flow battery electrolytes can be reused indefinitely • Good for long duration energy storage • Mechanical components can be likely recycled	• Most flow batteries now use Vanadium, which must be mined in large quantities • Spillage can be an issue; flow batteries must be contained • Some components will not be recyclable
	Sodium Sulfur	• Significant grid-connected operational utility data	• Potential for fires • Requires energy input to maintain operating temperature
	Zinc Air	• Benign components with not toxicity	• Low efficiency (40%-50%)
	Aqueous	• Claimed to be completely benign water-based construction	• Lower efficiency than Lithium Ion
Thermal	Ice Air Conditioners, Chilled water, Hot water	• Simple, highly recyclable mechanical systems • Non-toxic components	• May not provide fast grid operations • Can only provide benefits based upon the building cooling/heating needs

3. Energy Storage Improves Grid Operations through Replacement and Efficiency Gains

Energy storage connected to the grid can produce substantial benefits to the grid. Until recently, technology costs and lack of operational data have hindered widespread adoption and interconnection of energy storage onto the grid, but the following examples show that significant adoption is becoming a reality:

- California AB 2514: Mandate for 1.325 GW of storage in CA by 2020;
- Southern California Edison 261 MW procurement;
- CA Self Generation Incentive Program funding extended through 2019;
- ONCOR (Texas Utility) wants to invest $5.2 Billion in storage;
- NY Reforming the Energy Vision (REV); and
- AZ Tucson Electric Power seeking 10 MW storage under a 10-year agreement.

These and other energy storage developments show that storage improves grid operations through replacement of conventional alternatives and quantifiable efficiency gains. Used appropriately, energy storage can increase grid efficiency, reduce the delivered cost of energy and ancillary services, increase reliability, and reduce infrastructure requirements. Compared to traditional generation or transmission resources, energy storage is typically highly accommodating with regard to sizing, siting, and permitting, so it can be located closer to load, or closer to grid congestion points, than other options. As discussed in the IRP-specific comments below, recent energy storage procurement shows that costs are lower than anticipated, and costs continue to fall as production and integration of resources increases.

4. Examples of Energy Storage Grid Impacts

a) In PJM territory, 117 MW of fast responding energy storage resources are already providing fast regulation services. These new resources were so effective that they allowed PJM to reduce its regulation requirements from 1% of peak load in 2012 to 0.7% of peak load in 2013, without reducing system reliability. "Since October 1, 2012, PJM has lowered the Regulation Requirement on several occasions. In October 2012, the requirement was reduced from 1.0 to 0.78 percent of the peak/valley load forecast. It was further reduced in November 2012 from 0.78 to 0.74 percent. Finally, in December 2012, the Regulation Requirement was lowered to its current value of 0.70 percent of the peak/valley load. Even with these significant reductions to the Regulation Requirement, CPS1 and BAAL metrics have held steady throughout 2013 and show an increase starting in the summer of 2013…"[7]

b) As part of its 2013 capacity procurement Southern California Edison (SCE) evaluated multiple types of advanced energy storage to provide generation capacity, while further accounting for additional services that could be provided by these resources such as frequency regulation. As a result, SCE not only authorized a 100 MW battery energy storage resource in Long Beach, but additionally procured 160 MW of customer sited energy battery and thermal storage, all of which will be located in the capacity-constrained Los Angeles Basin. The new energy storage resources will allow SCE to add additional local capacity to its system without incurring transmission, siting, and interconnection costs that might have been required by traditional resources.

c) Energy storage is a natural fit for renewable grid integration. This has been demonstrated by Duke Energy's recently installed 36 MW battery energy storage system specifically for regulation and wind shifting services in Notrees, Texas. AES' Laurel Mountain project delivers 32 MW of regulation and wind smoothing in West Virginia. SCE recently commissioned a 32 MW battery unit in Tehachapi, California sited near significant wind resources.

d) Another example of improving grid efficiency is through economic deferral of distribution equipment upgrades. Utilities typically require large-scale distribution upgrades due to load growth or high renewable penetration. Utilities install these upgrades to service customers only during periods of highest demand or highest distributed generation. By their nature, these periods occur only during a limited number of hours per year. As such, local energy storage, installed either at utility locations or at customer sites, can be highly effective at deferring or avoiding costly infrastructure upgrades. Pacific Gas and Electric (PG&E) has already installed two

[7] PJM Performance Based Regulation: Year One Analysis.

systems for distribution deferral. The first is a 2 MW system at its Vaca Dixon substation, which, in addition to distribution services, is selling ancillary services into CAISO wholesale markets. PG&E's second system is a 4 MW resource at the end of a distribution line in Silicon Valley; it provides voltage stabilization for customers, as well as up to six hours of backup energy in the case of a grid outage.

Sierra Club provided this storage overview because energy storage is a very diverse asset class, providing benefits across the electric power system. Appropriately implemented, energy storage will enable cleaner, more reliable electric power systems in the U.S. However, before implementation, utilities, customers, and regulators must be fully informed of the true costs and benefits associated with this emerging technology.

C. Sierra Club's Energy Storage Comments Specific to the IRP's Analysis

For PacifiCorp's 2015 IRP, the company again included rudimentary analyses its consultant HDR Engineering has been developing since 2011.[8] Still, even this basic study contained critical flaws that undermine the benefits of energy storage and overstate the costs. These flaws could result in the company further delaying any action to deploy this crucial resource for years to come.

1. The IRP Greatly Overestimated the Actual Cost of Storage Resources

PacifiCorp's 2015 IRP estimated the cost of leading technologies at more than six times the cost of energy storage resources being quoted and procured by utilities elsewhere in the U.S. The IRP included three critical errors: 1) The IRP estimated costs per hour of advanced energy storage resources based upon historical costs, which are two to three times the costs of energy storage being procured by utilities in the 2020 timeframe. 2) PacifiCorp's evaluation quoted system costs using approximately double the hours required by other utilities, based upon a worst-case energy storage technology. 3) The IRP estimated future replacement costs of energy storage at the same price as current costs, in conflict with all future technology cost curves.

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[8] "A consultant study was initiated in 2011 on incremental capacity value and ancillary service benefits of energy storage. HDR Engineering (HDR) was retained by PacifiCorp to perform an Energy Storage Study to evaluate a portfolio of energy storage options." 2013 IRP at p.254.

2. The IRP Omitted Key Benefits from the Energy Storage Analysis

The 2015 IRP analysis excluded the key benefits that fast responding energy storage resources can provide the PacifiCorp system. Energy storage is a resource that can provide fast response to changing grid conditions. Advanced energy storage technologies can ramp to full capacity in seconds and switch rapidly and seamlessly between charging and discharging behavior. As shown below, other utilities have found that advanced energy storage resources can provide peak capacity, fast frequency regulation, improved utilization of variable renewable energy, and reduced grid emissions and costs. PacifiCorp's evaluation of energy storage, however, focused solely on shifting energy in bulk from one time of day to another, while proposing that a more complete evaluation be completed at a future time.

Building its analysis around these two overarching errors, the IRP's conclusions on the cost and benefit of storage are not useful from a planning perspective. In fact, the IRP's faulty conclusions may actually preclude energy storage procurement; storage that could provide a more cost effective and reliable alternative to the conventional resources included in the plan.

3. The IRP Significantly Overestimated Current Energy Storage Costs

a) The IRP's lithium ion battery energy storage cost assumptions on a cost/kilowatt hour basis are two to three times higher than publically available figures.

In the IRP, the company quoted lithium ion prices of $800-$1200 per kilowatt hour.[9] But then it goes on to admit that it used the highest lithium ion costs listed by HDR Engineering, or $1200 per kilowatt hour.[10]

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[9] IRP Table 6.7 in Volume I.
[10] Id. at p. 117.

Table 6.7 – HDR Energy Storage Study Summary Cost and Capacity Results (2014$)

	Flywheel	Li-Ion	NaS	VRB	Pumped Storage	CAES
System Cost ($/kW and/or $/kWh)	$2,862 per kW	$800 - $1,200/kWh (High Energy)	$4,000/kW	$675/kWh	$1,700-$2,500/kW	$2,000-$2,300/kW
Rated System Size (MW)	20	1 - 32	1	1	600	300+
Rated Capacity (hours)	0.25	1 (High Energy)	7.2	1	8 to 10	8+
Roundtrip, AC to AC efficiency (%)	85	91	70 – 75	65 – 75	75 – 82	64

However, PacifiCorp's figures do not reflect recent storage costs. For example, Southern California Edison data indicates that recent capacity procurement for viable Li-Ion projects were below $400/kilowatt hour for projects installed in the 2020 timeframe. The exact SCE figure remains confidential, but additional recent numbers from the Brattle Group support this figure. The Texas transmission utility Oncor has received bids for $375/kilowatt hour[11] for complete systems in 2020. These numbers are less than one third of the values included in Pacificorp's IRP on a kilowatt hour basis.

b) The IRP incorrectly sized Lithium Ion battery storage systems at 7.2 hours rather than a 3-4 hour system. This IRP sizing error further increased system costs.

In the IRP, the company multiplied the cost of an energy storage system per kilowatt hour by the total system duration in hours in order to achieve a total system cost per kilowatt. It then went on to multiply the cost per kilowatt by the number of kilowatts required to achieve a complete energy storage resource. According to the IRP, "*The common operating basis is defined by the sodium-sulfur (NaS) battery and all systems were compared on storing 7.2 hours of energy.*"[12]

This is incorrect. Peak power requirements in PacifiCorp's system are unlikely to require 7.2 hours of discharge by an energy storage resource. A key benefit of most energy storage

[11] The Brattle Group, *The Value of Distributed Electricity Storage in Texas (November 2014)* http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf?1415631708.
[12] IRP p. 117.

resources comes from their ability to start almost instantaneously, allowing grid operators to avoid unit starts by other resources for a limited peak. In other western states, energy storage procurements have focused on three to four hours as an optimal size for energy storage resources.[13]

Using PacifiCorp's 7.2 hour discharge requirement would lead to a cost approximately double that of the cost of a three to four hour system. By basing all battery energy storage duration on the worst case technology, PacifiCorp calculated system costs based upon an unreasonable number of kilowatt hours.

c) The IRP incorrectly assumed future replacement costs would be the same as current procurement costs.

According to the IRP, *"The replacement cost is the average of the initial cost range."*[14] Based upon that statement, the IRP estimates a replacement cost of $1000/kWh for lithium ion batteries, which is only slightly lower than the IRP's estimate of $1200/kWh for the upfront cost of the system.

It is correct that the batteries in a battery-based energy storage system will have a more limited life than conventional generators, usually 10-15 years in a utility scale application. However, the statement above evidences a fundamental misunderstanding of energy storage systems and future technology cost curves.

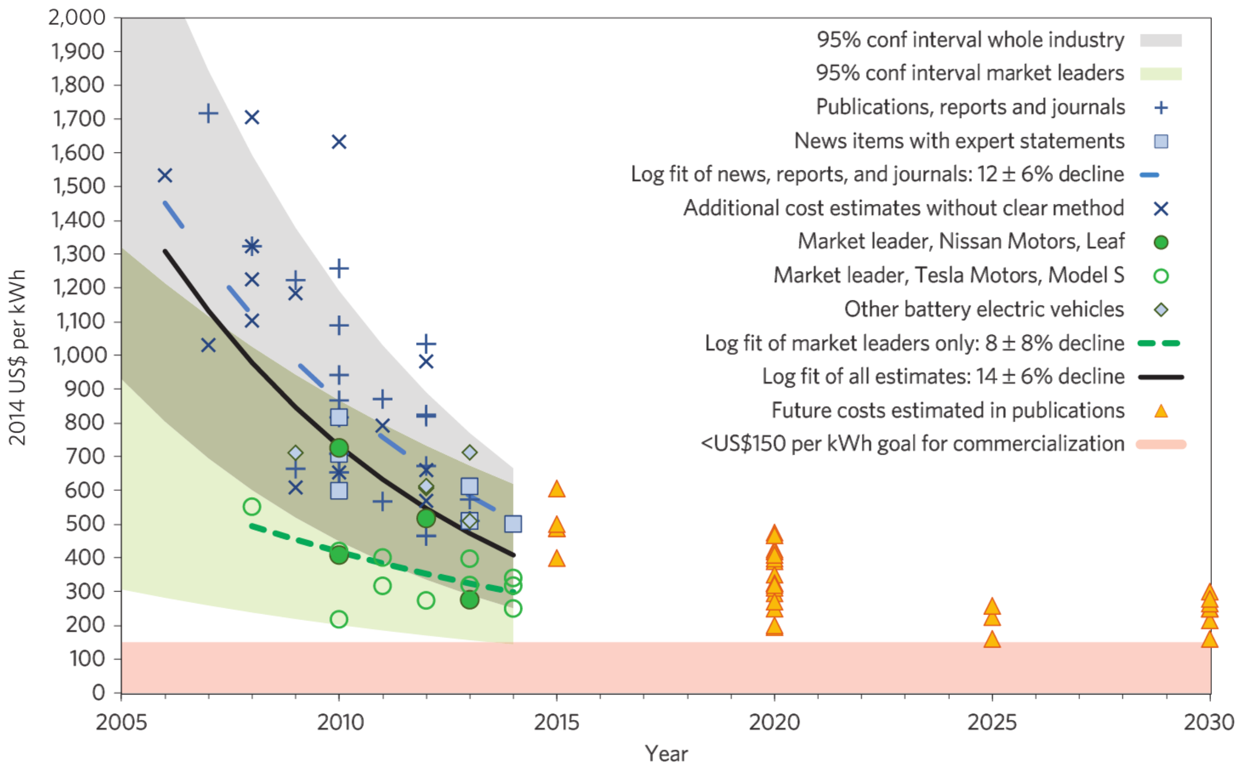
The first problem is that the IRP assumes that a scheduled replacement of the batteries in an energy storage system will require replacing the entire system, at a cost nearly as much as that of the whole system. However, replacement of the batteries in an energy storage resource does not necessitate replacement of the entire system. A significant percentage of the system, including wiring and site infrastructure, interconnection, and transformers, will still be perfectly useable. A standard 10-15 year battery replacement, along with replacement of certain power

[13] Energy storage procurement in Southern California: SCE: https://www.sce.com/wps/wcm/connect/0a312536-5ba4-4153-a3bd-0859e15badeb/TrackI_SCELCRProcurementPlanPursuanttoD1302015.pdf?MOD=AJPERES; SDG&E: http://www.sdge.com/sdge-energy-storage-system-%E2%80%9Cess%E2%80%9D-2014-distribution-reliability-power-quality-program-request; Procurement in Northern California. PG&E: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/RFO/ES_RFO2014/index.page; Ontario: http://www.ieso.ca/Pages/Participate/Energy-Storage-Procurement/default.aspx.

[14] See IRP at p.117.

electronics, will cost significantly less than the initial installation.

The second problem with PacifiCorp's approach is that it is not based upon any future cost forecast. Battery costs are falling rapidly as deployments increase for grid storage and electric vehicles.[15] Battery replacement costs 10 years from resource interconnection will be a fraction of current costs.



Likewise, inverter and other power electronics' costs continue to fall as they are installed in increasing volume, leveraging the cost reductions in the solar industry.[16]

Therefore, a more reasonable estimate of future battery replacement costs is that they will be at least 50% lower than initial system costs. In comparison, the IRP represents that replacement costs will be only about ~17% lower than the initial cost. Given that replacement costs are critical to the Total Resource Cost, this error further prevents the battery energy storage

[15] Björn Nykvist & Måns Nilsson, Rapidly falling costs of battery packs for electric vehicles (March 2015) http://www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html.
[16] Deutsche Bank, Solar Grid Parity in a Low Oil Price Era, February 2015.

resource from appearing viable.

d) The IRP's cost assumptions created a cost estimate that is seven times greater than the anticipated costs of an appropriately-sized battery storage resource.

Importantly, all these erroneous cost assumptions are multiplied together, magnifying each individual error. Given the above inaccurate assumptions about the duration, upfront cost, and replacement costs of batteries, PacifiCorp's total assumed costs are approximately seven times greater than the cost of a realistic battery storage procurement.

	PacifiCorp Assumptions	**Likely 2020 Costs**
Up front cost per kilowatt hour	$1,200	$375
Replacement cost per kilowatt hour	$1,000	$187.50[17]
Duration in hours	7.2 hours	4 hours
Total system cost per kilowatt	$8,640	$1500
Total replacement cost per kilowatt	$7,200/kW	$750 /kW
Total of upfront + replacement cost	**$15,840 /kW[18]**	**$2250 /kW[19]**

4. The IRP's analyses excluded key benefits of energy storage

On the benefit side of the benefit/cost equation, PacifiCorp excluded the key benefits of energy storage except for energy shifting.

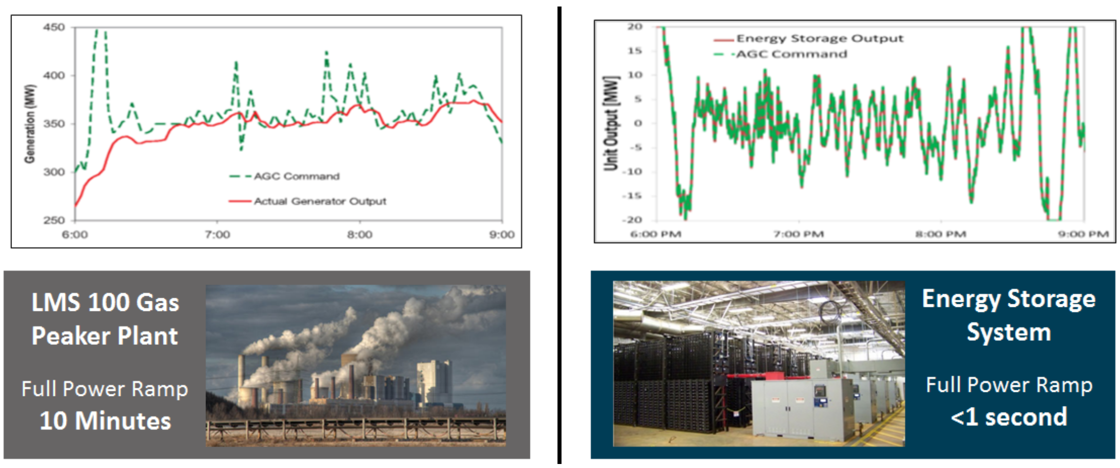
a) The IRP omitted sub-hourly dispatch.

According to the IRP, *"Optimizer does not explicitly capture operating reserve benefits of storage projects.*[20] And, *"Other grid benefits, such as frequency regulation are not captured in System Optimizer or PaR."*[21]

The company's model caused omission of critical benefits in the IRP analysis. For

[17] Replacement cost is more likely to be half the upfront cost, as described above.
[18] Upfront Cost ($1200/kWh * 7.2 hours) + Replacement Cost ($1000/kWh * 7.2 hours).
[19] Upfront Cost ($375/kWh * 4 hours) + Replacement Cost ($187.50/kWh * 4 hours).
[20] IRP at p. 205.
[21] Id. at p. 206.

example, in addition to capacity, energy storage provides several additional benefits such as providing operating reserves and frequency regulation. The following comparison shows a conventional gas peaking power plant to an energy storage resource when following a frequency regulation signal. The regulation signal is shown in green, with the output of the resource in red. The conventional plant is slow to respond, while the energy storage resource follows the regulation signal with very high accuracy.

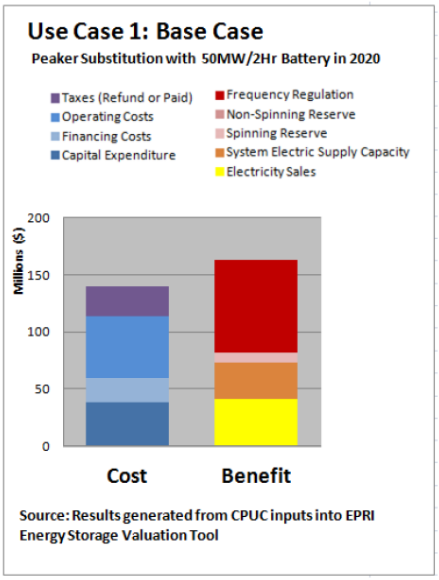


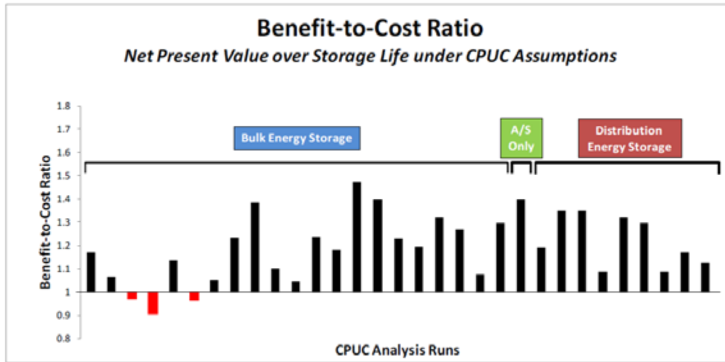
Source: Kirby, B. "Ancillary Services: Technical and Commercial Insights." Wartsilla, July, 2007. pg. 13

Providing an analysis which excludes these benefits, as the IRP did, undermines the analysis altogether.

The Electric Power Research Institute conducted a detailed cost/benefit analysis in California that accounted for a greater number of energy storage benefits. The result was that the majority of cases were shown to be cost effective.[22]

[22] EPRI, Cost-Effectiveness of Energy Storage in California: Application of the EPRI Energy Storage Valuation Tool to Inform the California Public Utility Commission Proceeding R. 10-12-007, June 2013.





Source: Electric Power Research Institute

While it is not certain that results in PacifiCorp territory would match the results in California, it is clear that a proper evaluation is called for at this time.

b) The IRP assumed that the energy storage capacity factor was 25%, reducing its value further.

The IRP assumed the capacity factor of the battery energy storage resources would be 25%.

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2014 Dollars ($)		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	¢/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
Blundell Dual Flash 90% CF		90%	62.04	na	0	-	1.30	0.00%	0.00	-	-	63.34	(16.33)	47.02
Greenfield Binary 90% CF		90%	83.40	na	0	-	1.30	0.00%	0.00	-	-	84.70	(16.33)	68.37
Generic Geothermal PPA 90% CF		90%	-	na	0	-	93.46	0.00%	0.00	-	-	93.46	-	93.46
2.0 MW turbine 29% CF WA/OR		29%	75.74	na	0	-	0.00	0.00%	0.00	3.06	-	78.80	(18.37)	60.43
2.0 MW turbine 31% CF UT/ID		31%	72.31	na	0	-	0.00	0.00%	0.00	3.06	-	75.36	(18.37)	56.99
2.0 MW turbine 43% CF WY		43%	51.49	na	0	-	0.67	0.00%	0.00	3.06	-	55.21	(18.37)	36.85
PV Poly-Si Fixed Tilt 26.5% CF		27%	120.97	na	0	-	0.00	0.00%	0.00	0.76	-	121.74	(5.11)	116.62
PV Poly-Si Single Tracking 31.6% CF		32%	108.01	na	0	-	0.00	0.00%	0.00	0.76	-	108.78	(4.54)	104.24
PV Poly-Si Fixed Tilt 26.5% CF		27%	101.37	na	0	-	0.00	0.00%	0.00	0.76	-	102.14	(4.23)	97.91
PV Poly-Si Single Tracking 31.6% CF		32%	90.98	na	0	-	0.00	0.00%	0.00	0.76	-	91.74	(3.76)	87.98
PV Poly-Si Fixed Tilt 25.4% CF		25%	110.02	na	0	-	0.00	0.00%	0.00	0.76	-	110.78	(4.60)	106.17
PV Poly-Si Single Tracking 29.2% CF		29%	102.66	na	0	-	0.00	0.00%	0.00	0.76	-	103.42	(4.26)	99.16
CSP Trough w Natural Gas - 24% Solar		33%	178.19	na	474	12.59	0.00	0.00%	0.00	0.76	-	191.55	(8.21)	183.34
CSP Tower 24% CF		24%	226.78	na	0	-	0.00	0.00%	0.00	0.76	-	227.55	(10.75)	216.80
CSP Tower Molten Salt 30% CF		30%	212.60	na	0	-	0.00	0.00%	0.00	0.76	-	213.36	(10.32)	203.05
Forestry Byproduct		91%	45.04	na			0.96					NC	-	NC
Pumped Storage (5280 MWh)		37%	68.41	78%	481	40.29	3.49	0.00%	0.00	-	-	112.20	-	112.20
Lithium Ion Battery (7.2 MWh/day)		25%	496.91	91%	474	33.83	0.00	0.00%	0.00	-	-	530.75	-	530.75
Sodium-Sulfur Battery (7.2 MWh/day)		25%	238.79	73%	474	42.47	0.00	0.00%	0.00	-	-	281.26	-	281.26
Vanadium RedOx Battery (7.2 MWh/day)		25%	289.76	70%	474	43.99	0.00	0.00%	0.00	-	-	333.75	-	333.75
Advanced Fly Wheel (1667 KWh/day)		5%	507.79	85%	474	36.22	0.00	0.00%	0.00	-	-	544.02	-	544.02
CAES (Mona, UT; 83.4% eff; 2,400 MWh)		33%	85.22	83%	474	36.92	2.28	10.38%	0.24	-	-	124.66	-	124.66
Advanced Fission		86%	102.44	na	0	-	9.80	0.00%	0.00	-	-	112.24	-	112.24
Small Modular Reactor x 12		86%	65.65	na	0	-	8.70	0.00%	0.00	-	-	74.35	-	74.35

But the penalty for starting and operating an energy storage resource is negligible compared to the startup costs for a conventional power plant. Also, energy storage resources can provide services like frequency regulation, ramping, spinning reserves intermittently, and charging and discharging, which allows them to provide services at a much higher capacity factor than their duration would indicate.   Therefore, the company's 25% capacity factor assumption is arbitrarily low.

5. Recommendation

The 2015 IRP's energy storage analysis was flawed in terms of both costs and benefits. Given the company's baked-in limitations, it was inevitable that the IRP would conclude that the technology's purported high cost and minimal benefits would eliminate its selection as a resource in the preferred portfolio.

A current and informed analysis is required and would show that energy storage could allow PacifiCorp to cost effectively and reliably reduce overall system and operational costs by adding energy storage. It is well past time for the company to do this work.

Sierra Club looks forward to working with PacifiCorp on an improved analysis of energy storage, with more reasonable cost estimates and a more accurate accounting for the intra-hourly benefits.

IV. CONCLUSION

Sierra Club appreciates the opportunity to comment on PacifiCorp's 2015 IRP. We look forward to working with the company to improve the plan as described above and in the attached report.

August 27, 2015

Respectfully submitted,

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Review of the Use of the System Optimizer Model in PacifiCorp's 2015 IRP

Including treatment of the Clean Power Plan and economic coal plant retirement

Prepared for Sierra Club, Western Clean Energy Campaign, Powder River Basin Resource Council, Utah Clean Energy, and Idaho Conservation League

August 21, 2015

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EXECUTIVE SUMMARY

PacifiCorp utilized the System Optimizer model to conduct system-wide planning for its 2015 IRP. For this report, Synapse reviewed the model, reviewed PacifiCorp's inputs and configuration choices for the model, and conducted several sensitivity scenarios. The intent of these sensitivities was to allow the model to better optimize decisions in the face of planning constraints faced by PacifiCorp, and to demonstrate a more flexible and transparent approach. The Synapse runs considered endogenous retirements, a significant PacifiCorp omission, as well as alternative means of Clean Power Plan (CPP) compliance and renewable cost assumptions.

PacifiCorp chose to hard-code all power plant retirements into the System Optimizer model, based on an *a priori* determination of four Regional Haze compliant scenarios. This approach is problematic because final regional haze requirements remain unknown and it severely limited the flexibility in finding a least-cost plan. The endogenous retirement sensitivity run by Synapse demonstrates clearly that the units chosen by PacifiCorp for retirement under the Preferred Portfolio are not necessarily the most economic units to retire under a more flexible approach. Hunter, Huntington, and Naughton all appeared potential candidates for retirement, but were not explored in PacifiCorp's IRP.

The Synapse team also implemented CPP compliance via a mass-based approach, a more transparent and easily optimized planning process than PacifiCorp's in-house "111(d)" compliance tool. The PacifiCorp "111(d)" tool required substantial manual manipulation by the IRP team at PacifiCorp, and ignored both the computational capability of the optimization tools built into System Optimizer, and largely discounted the value of using a capacity expansion tool in the first place. When Synapse adjusted the model to allow endogenous retirements, distinctly different trajectories and decisions were selected from PacifiCorp's Preferred Portfolio.

By forcing units to retire based on *a priori* assumptions, PacifiCorp's IRP development process violates basic principles of least-cost resource planning, and takes a major step backwards from progress made by PacifiCorp in its 2013 IRP. By effectively only modeling rate-based compliance with the Clean Power Plan, PacifiCorp failed to seek a least-cost plan to meet customer requirements and emissions limits.

1. PACIFICORP'S IMPLEMENTATION OF CLEAN POWER PLAN AND COAL RETIREMENTS IN 2015 IRP

1.1 Clean Power Plan Implementation

PacifiCorp's 2015 IRP modeled a version of EPA's 2014 draft Clean Power Plan (CPP). Finalized in August 2015, the purpose of the CPP is to limit CO_2 emissions from existing sources after determining a best system of emissions reductions (BSER). The draft CPP, upon which the 2015 IRP is ostensibly based, allowed states to meet either mass-based emissions targets (measured in total tons of emissions), or rate-based emissions targets (measured pounds per megawatt-hour). In a rate-based compliance scenario, renewable energy and energy efficiency can "dilute" fossil emissions. PacifiCorp oriented its 2015 IRP around a single interpretation of the proposed CPP, using the dominant compliance mechanism—rate-based compliance for individual states—with the assumption that renewable energy and energy efficiency programs were fully fungible across states. This narrow focus left PacifiCorp in the position of structuring many of its assumptions and operational restrictions around this single expectation of the regulation, and does not comport with reasonable least-cost utility planning in the face of the uncertainty the Company faced at the time.

The draft CPP set forth two basic routes for reducing state CO_2 emissions from existing sources: states could either meet the rate-based target using a combination of "building blocks"[1] or other programs, or meet an alternate mass-based target, measured in total tons of CO_2. EPA's draft allowed states to choose the metric by which they measure compliance. The rate-based mechanism is a fairly unique measure of compliance, while the mass-based system is similar to the result of a cap-and-trade scheme, currently employed for national sulfur dioxide (SO_2) emissions under the Acid Rain Program, regionally for nitrogen oxides (NO_X) under a budget trading program, and for CO_2 in California and Regional Greenhouse Gas Initiative (RGGI) states. The rate-based approach, at least as used in EPA's target-setting in the draft rule, assigned credit for renewable energy and energy efficiency programs implemented by entities in the state. The mass-based approach assigns credit for stack-based emissions reductions.

The rate-based compliance approach is, by all measures, far harder to model when optimizing for least-cost on a net present value basis. The mass-based approach is far simpler. Since at least the mid-1990s with the advent of SO_2 and NO_X trading programs, energy planners have understood that it was appropriate to model mass emissions caps using an opportunity cost for generators, regardless of whether emissions allowances were tradable. Every ton of emissions avoided by reducing generation eases compliance and thus has monetary value. In "hard cap" mass-emissions reduction modeling,

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[1] EPA structured the draft CPP around four fundamental "building blocks" that represented possible means for achieving the established emissions standard: (1) increasing existing coal plant efficiency, (2) displacing coal generation with existing natural gas, (3) increasing renewable energy acquisitions, and (4) implementing energy efficiency programs. Taken together, EPA estimated that these programs would reduce emissions by a certain amount in each state.

emissions have a shadow price—i.e., the cost of incrementally shifting production to lower emissions sources, on a per-ton basis. In a tradable credit program, the emissions have a direct monetary value, but the meaning is the same. In both cases, the cost of emissions is typically considered a variable cost—i.e., higher costs for high emissions resources should result in lower production.[2]

A rate-based trading mechanism is much more difficult to structure in capacity expansion models. Most off-the-shelf dispatch and capacity expansion models have not been structured to support this mechanism. Nonetheless, rate-based compliance is the mechanism that PacifiCorp has chosen to utilize in almost every one of the core cases in the 2015 IRP. PacifiCorp's System Optimizer model is not configured to determine a least-cost plan for rate-based compliance, but it is readily configured to determine a least-cost plan for mass-based compliance.

Out of the 15 "Core Cases" modeled by PacifiCorp, 12 assumed that PacifiCorp would comply on a rate basis. One assumed that PacifiCorp would not need to comply with the CPP at all, and just two assumed that PacifiCorp would comply on a mass basis. These two cases (C12 & C13) restricted the model from retiring coal units as a form of compliance, and thus cannot be representative of a possible least-cost plan to meet emissions targets.

To overcome the barrier that System Optimizer cannot search for a least-cost rate-based compliant plan, PacifiCorp fundamentally misused the model, manually choosing and excluding resources in order to meet targets in different states. PacifiCorp developed its separate in-house "111(d)" tool specifically to develop user-specified portfolios that meet rate-based compliance. This tool required the PacifiCorp IRP team to manually distribute and balance renewable energy and energy efficiency credits amongst states, check for unit operational violations, and choose buildout options manually, rather than allowing the model to choose least-cost options.

By developing each individual portfolio manually, PacifiCorp undermined System Optimizer's ability to find least-cost plans. By choosing to model exclusively rate-based compliance, PacifiCorp hedged on one interpretation of EPA's draft rule, and failed to evaluate if mass-based compliance with economic unit retirement could result in lower cost outcomes.

1.2 Final Clean Power Plan as Compared to 2014 Draft

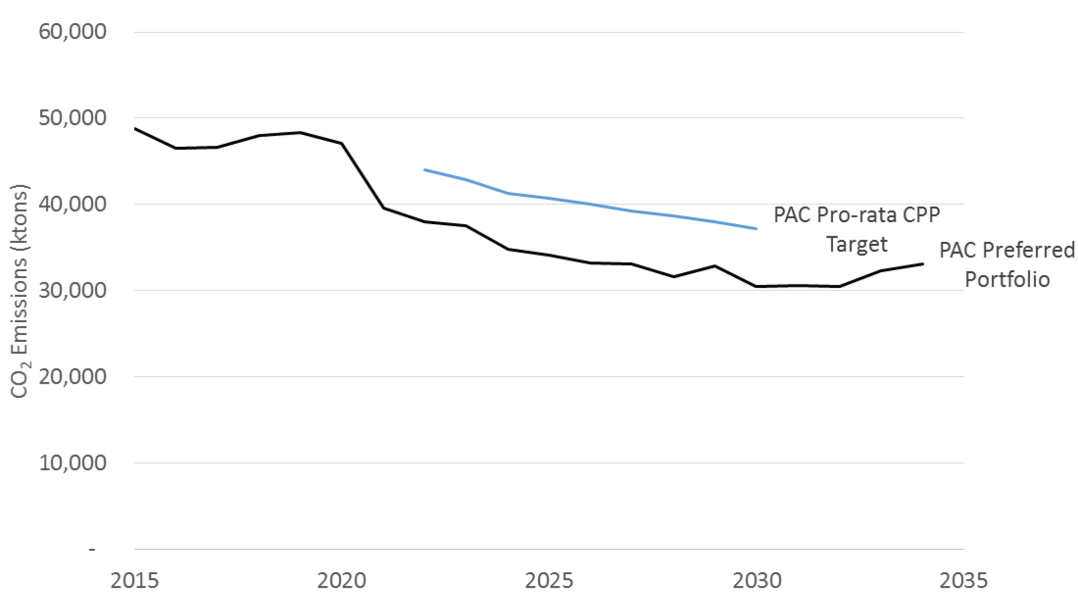
As acknowledged by the PacifiCorp IRP team, during the development of the 2015 IRP, neither the Company nor stakeholders could know the final form of the CPP. As a result, PacifiCorp embarked on an ambitious and challenging plan to model the specifics of the rate-based proposed rule based on state-average emission rates. While this option remains a compliance pathway in the final rule, the final rule eliminated the eligibility of the vast majority of renewable energy PacifiCorp used to meet its compliance limitations in the IRP. The final rule also provided additional compliance pathways, including

[2] This mechanism is described in fair detail in a paper from Resources for the Future from 2008: Burtraw, D and D. Evans. 2008. Tradable Rights to Emit Air Pollution. Resources for the Future Discussion Paper. RFF DP 08-08

unit-specific emissions rates, alternative rates based on a weighted average state emission rate, and mass-based targets with and without new source complements (i.e., new fossil units).

While PacifiCorp's Preferred Portfolio appears to comply with the final mass-based goals, based on PacifiCorp's pro-rata share of emissions in Arizona, Colorado, Montana, Oregon, Utah, Washington, and Wyoming, (shown in 1.3 Why Mass-Based Compliance and Economic Coal Retirement Matters), it does not show that the plan represents a least-cost pathway towards compliance.

Figure 1: PacifiCorp system-wide CO_2 emissions compared to mass-based target



1.3 Why Mass-Based Compliance and Economic Coal Retirements Matter

PacifiCorp's coal fleet has faced, and continues to face, a variety of new environmental regulations that impose costs and operating restrictions. Since 2008, PacifiCorp has engaged in significant capital and operating expenditures to comply with Regional Haze Mercury and Air Toxics Standards (MATS) rules. Going forward, PacifiCorp's coal units will face additional Regional Haze costs, and face new National Ambient Air Quality Standards (NAAQS), as well as a coal combustion residual (CCR) rule, and CO_2 emissions costs from the Clean Power Plan.

These future costs for coal plants raise the question of whether PacifiCorp specifically avoided reviewing mass-based compliance and economic unit retirements not because the model couldn't handle the inputs or the analysis was too complex, but because such modeling would result in numerous coal unit retirements that are not strategically advantageous to PacifiCorp at this time

Why is it useful to model economic coal unit retirements? Coal comprises approximately 50 percent of PacifiCorp's owned capacity, and nearly 70 percent of its generation. Even eliminating any new gas builds and taking into account expected near-term retirements, PacifiCorp has excess energy resources through at least 2024.[3] While the existing fleet remains, the system has very little headroom for new low-emissions, low-cost resources. Unless energy efficiency, renewable energy, and other low emission resources have the opportunity to compete in a level playing field against PacifiCorp's existing fleet, we cannot learn how much of a benefit ratepayers would find from a cleaner fleet.

In a 2011 Wyoming rate case,[4] Powder River Basin Resource Council argued that PacifiCorp had failed to appropriately evaluate if the retirement of Naughton 1 & 2 would be less expensive than installing expensive environmental retrofits at those units. As a result of the settlement emerging from that proceeding, PacifiCorp agreed to evaluate future environmental capital expenditures in litigated dockets. Shortly thereafter, PacifiCorp filed a Certificate for Public Convenience and Necessity (CPCN) for retrofits at Naughton 3. During that proceeding, intervenors discovered errors in PacifiCorp's analyses, and upon revising the model, PacifiCorp discovered that Naughton 3 could not be considered economically beneficial. In mid-2012, PacifiCorp withdrew its application, effectively proving that economic coal retirements mattered in decision-making.

In its 2011 IRP (March 2011), PacifiCorp effectively ignored pending environmental regulations for the purposes of the IRP, assuming that existing coal units would continue operations unabated. That IRP conducted a "proof-of-concept modeling of coal unit replacements,"[5] but disclosed little about the study or its specific results. The study was not used to inform the action plan or concurrent capital expenditures.

Around 2011, Ventyx (now ABB), the model vendor for System Optimizer, upgraded the ability of the capacity expansion model to allow for "endogenous" coal retirements. In other words, the model became capable of choosing whether existing thermal units should be operated, retired, or changed (i.e., converted to natural gas), independent of user choice. This capacity had not been used by PacifiCorp in the 2011 IRP, but under regulatory pressure, PacifiCorp expanded the study in the 2011 IRP Update (March 2012) to review investments at Naughton, Jim Bridger, Hunter, Craig, and Hayden.[6] In this study, PacifiCorp reviewed the economics of retiring or retrofitting individual units. In addition, PacifiCorp began testing the model's ability to endogenously retire coal units.

PacifiCorp's IRP methodology peaked in 2013, when PacifiCorp significantly improved its transparency and logic.[7] In that IRP, low gas prices and high CO_2 prices led to the retirement of the vast majority of

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[3] Results from 2015 IRP, Core Case CO5a-3Q. 2015.

[4] In the Matter of Rocky Mountain Power, Wyoming Docket No. 20000-384-ER-10 (Dec. 1, 2010).

[5] Termed the "coal plant utilization study." 2011 IRP, p180

[6] 2011 IRP Update, p. 67.

[7] In the 2013 IRP, PacifiCorp expanded the endogenous retirement capability of System Optimizer. Each unit was allowed to continue operation, or retire or convert to natural gas. The same endogenous retirement capacity was then used by PacifiCorp to examine investments in individual coal units for the purposes of Certificates of Public Convenience and Necessity in Wyoming and Pre-Approvals in Utah.

PacifiCorp's fleet.[8] Stakeholders suggested that, following this IRP, various sensitivities should be evaluated to assess the economic robustness of the fleet. The IRP had raised questions about units that had not previously been considered economically vulnerable.

The 2015 IRP provided an opportunity to refine PacifiCorp's IRP methodology, and start an informed conversation about ratepayer costs and benefits towards transitioning to a cleaner fleet. PacifiCorp found an opportunity in the Clean Power Plan to circumnavigate this conversation and to decide, without explanation, which units they felt should be retired and over what timeframe. PacifiCorp completely eliminated the endogenous retirement capacity of System Optimizer in all but one core case (C14a). In the remainder of the IRP, PacifiCorp instead chose a "Regional Haze Scenario" in which some units are retrofitted and others are converted or retired early. In every case, PacifiCorp simply programs in the retirement schedule, denying the opportunity for the model to choose an optimal path under environmental constraints. This complete turnaround is a shortfall in the 2015 IRP, and represents a significant step backwards by the utility in finding a least-cost plan to meet environmental compliance requirements.

Allowing the model to choose to retire units optimally results in a lower cost plan than when retirements are guessed by planners. PacifiCorp confirms this outcome for the case in which a CO_2 cost is also imposed: "When allowing endogenous coal unit retirements beyond those assumed for Regional Haze scenarios (core case C14a), costs are lower than the C14 portfolios developed with specific timing for assumed coal unit retirements."[9] In the 2015 IRP, PacifiCorp removed the opportunity for ratepayers to evaluate one of the most important elements of their fleet, coal retirement, and the singular, key decision of the IRP.

2. OVERVIEW OF SYNAPSE'S ANALYSIS

The Synapse team acquired System Optimizer to evaluate the impact of correcting the modeling deficiencies in PacifiCorp's IRP. Synapse began by constructing an optimized long-range resource plan, complete with economic coal unit retirements, mass-based CPP compliance, and with lower criteria

[8] From the 2013 IRP, p. 161: "Building upon modeling techniques developed in the 2011 IRP and 2011 IRP Update, environmental investments required to achieve compliance with known and prospective regulations at existing coal resources have been integrated into the portfolio modeling process for the 2013 IRP. Potential alternatives to environmental investments associated with known and prospective compliance obligations are considered in the development of all resource portfolios. Integrating potential environmental investment decisions into the portfolio development process allows each portfolio to reflect potential early retirement and resource replacement and/or natural gas conversion as alternatives to incremental environmental investment projects on a unit-by-unit basis. This advancement in analytical approach marks a significant evolution of the IRP process as it requires consideration of potential resource contraction while simultaneously analyzing alternative resource expansion plans."

[9] 2015 IRP, p. 210.

emissions than the PacifiCorp plan. The assessment built upon the Company's 2015 IRP System Optimizer database with four incremental changes to the model:

- **Mass-Based CPP Approach** via implementation of an annual CO_2 price in $/ton;
- **Endogenous Coal Unit Retirements** by relaxing constraints imposed by PacifiCorp on the model to prevent units from being retired;
- **Incorporation of Avoidable O&M** where major capital expenditures in the two years prior to retirement were avoidable, and deducted from "decommissioning" costs; and
- **Lower Renewable Energy Costs** based on recent cost estimates, in order to test the sensitivity of new build options to costs.

We discuss these incremental changes in further detail below.

2.1 Mass-Based CPP Approach via Carbon Pricing

PacifiCorp's System Optimizer model is not configured to determine a least-cost plan for CPP rate-based compliance. As described above, a mass-based approach would be much simpler to model and fit into the existing construction of the System Optimizer framework without requiring so many opaque steps. A straightforward way to model a mass-based target is via a CO_2 price. The Synapse team used the Synapse Low CO_2 Price forecast—representative of a Clean Power Plan compliance structure that is relatively lenient—to incorporate the CPP compliance requirement in PacifiCorp's long-range resource planning.[10]

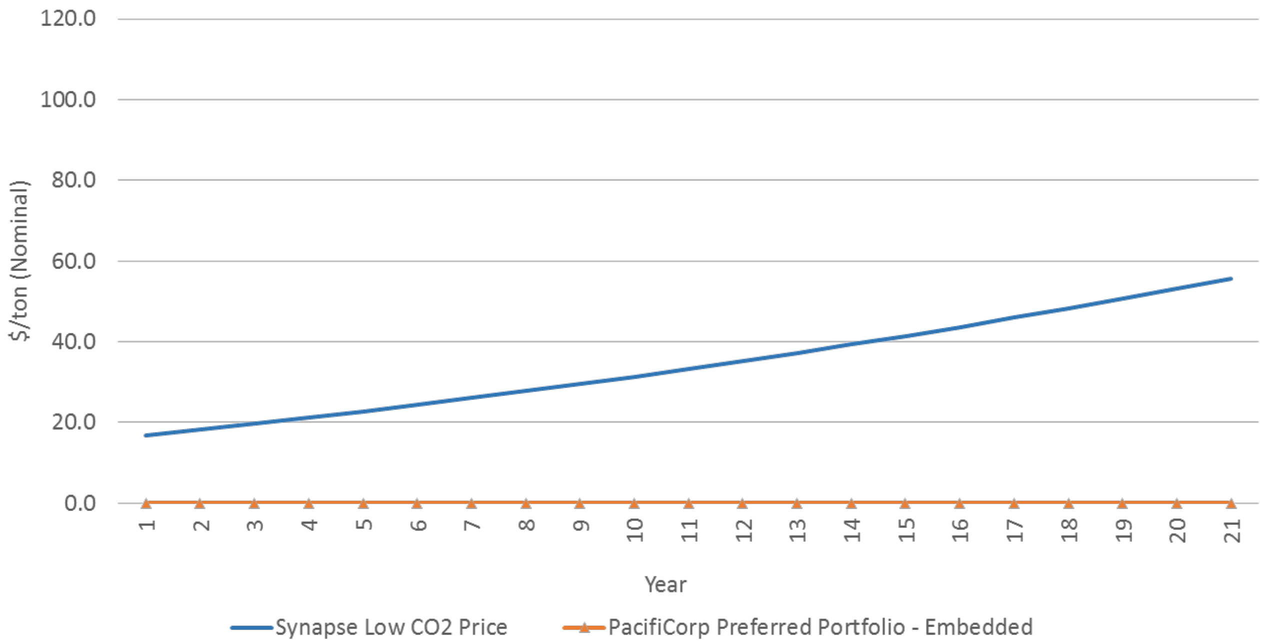
Figure 2 shows the Synapse Low CO_2 Price applied: from $16.7/ton in 2020[11] to approximately $41.4/ton in 2035 (nominal dollars). This is in comparison to the default Core 14a case price of $22/ton in 2020 rising to $76/ton by 2034. CO_2 prices in $/ton were modeled as a direct emissions cost at the unit-level, and translated into an equivalent $/MWh adder for market level transactions, including spot purchases and sales, and front office transactions (FOTs).[12]

[10] Luckow, P., E. A. Stanton, S. Fields, B. Biewald, S. Jackson, J. Fisher, R. Wilson. 2015. *2015 Carbon Dioxide Price Forecast*. Synapse Energy Economics.

[11] Modeling was performed prior to the release of the final Clean Power Plan rule, which moves compliance requirements to 2022.

[12] We assumed an incremental electricity price ($/MWh) adder to PacifiCorp's Preferred Portfolio market price, based on an implied tons CO_2/MWh from Core Case 14a (a case that *included* a carbon price) and Synapse's Low CO_2 price in $/tons CO_2.

Figure 2. Synapse CO_2 Low Price forecast



2.2 Endogenous Coal Unit Retirement

As noted above, in the 2015 IRP, PacifiCorp also completely eliminated the endogenous retirement capacity of System Optimizer in all but one core case (C14a), in which it allowed five coal units to be endogenously retired.[13] The Synapse team built upon this case, and the straightforward mass-based CPP compliance implementation described above, to enable the model to choose investments and retirements at all plants in 2020 and beyond.

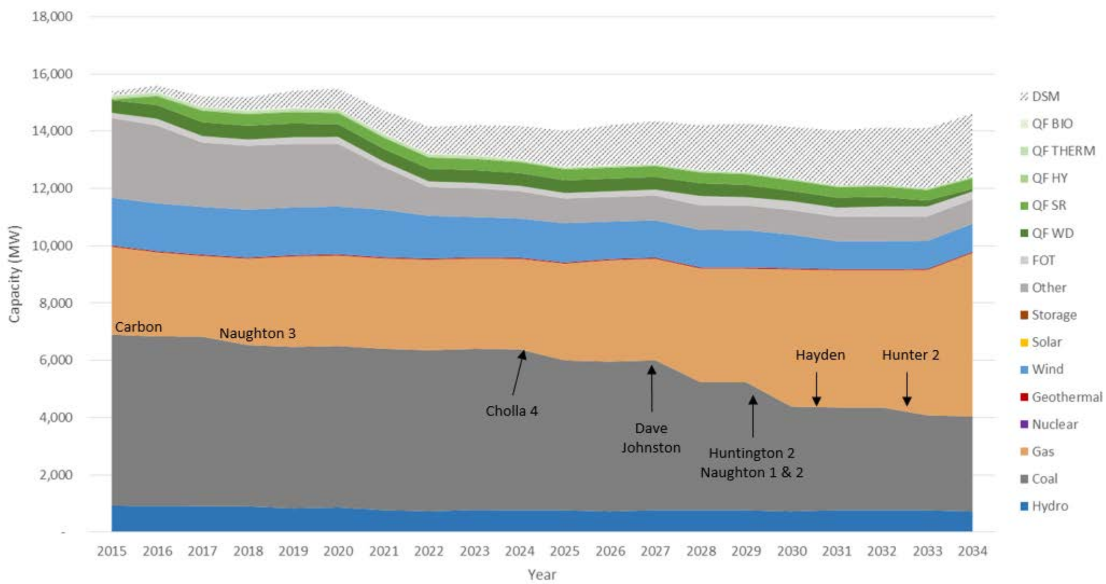
Results for generation capacity and coal unit retirements, summarized below in

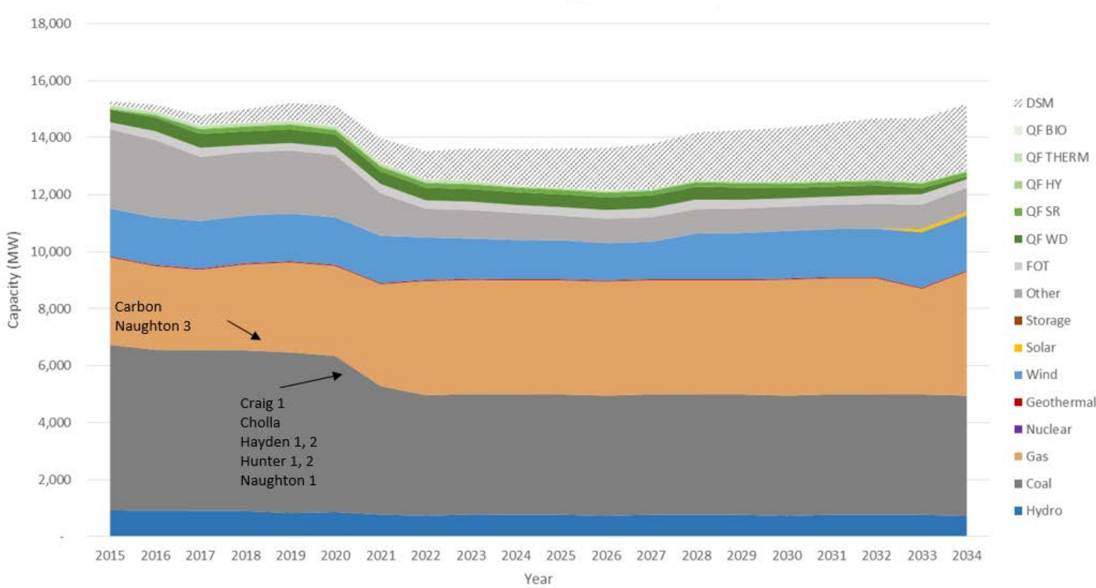
Figure 3, show that System Optimizer chooses a drastically different coal unit retirement schedule when allowed to choose retirements based on costs. The effect of allowing System Optimizer to find a least-cost resource plan by *choosing* which units to retire and build rather than *telling* it which units to retire and build, under a straightforward mass-based CPP compliance pathway, retires units earlier—beginning in 2020 with Hayden 1 & 2 and Craig 1, and followed by the retirement of Hunter 1, Naughton 2 and Cholla 4 in 2021, and Hunter 2 in 2022.

This is important because Hunter and Naughton are not identified in any of PacifiCorp's Regional Haze scenarios as potential near-term retirements, yet they are clearly marginal units in this analysis. Hayden, Craig, and Cholla are all the subject of recent PacifiCorp assessments and are similarly removed from consideration in the Core Cases of the 2015 IRP.

[13] C14a only allowed Hunter 1 & 3, Bridger 3 & 4, and Wyodak to be retired endogenously.

Figure 3. Generation capacity by year: PacifiCorp Preferred Portfolio (top) and Alternative IRP with 1) endogenous retirements and 2) mass-based CPP compliance (low CO_2 price)





Source: Synapse analysis.

2.3 Adjustment to Decommissioning Costs to Capture Avoidable O&M

Sound least-cost utility resource planning should appropriately avoid major capital expenditures immediately before a retirement. The decommissioning costs PacifiCorp included in its 2015 IRP include both the costs to actually retire and dismantle the plant, as well as recovery of any stranded costs incurred during the analysis period. For example, incurring a capital expense in one year entails a de-facto hurdle to retire the next year, because the model assumes that stranded capital investments are moved into a regulatory asset and recovered in full. Aside from the open question of whether PacifiCorp can or should assume that stranded costs are recoverable for retiring units (or should be considered a forward-going cost), the assumption makes little sense for logical forward planning. In the years leading up to a unit's phase-out, it would unreasonable to incur major capital expenditures. Why invest in life extension measures for a unit that has only a few years of life remaining?

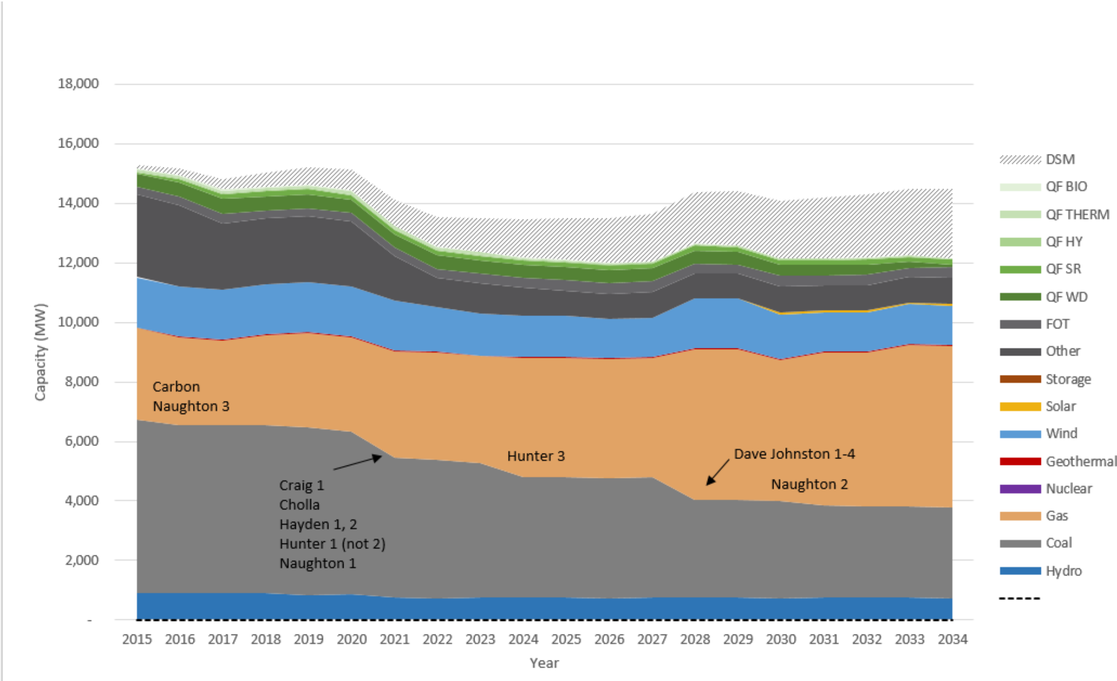
To factor in this reality, the Synapse team added a third cost term to the total decommissioning cost of a unit: avoidable fixed O&M and run rate capital. Synapse assumed that in the two years prior to a unit going offline, retirement is known and major capital expenditures can be avoided. Ongoing fixed O&M expenses are still incurred (although major outages are avoided), as are known and potential future requirements for SCRs on most units (Synapse's endogenous retirement case assumes Reference Regional Haze assumptions of the IRP).[14]

By adjusting the decommissioning costs in this manner, we continued to assume that PacifiCorp recovers stranded investments in existing units when they retire, but allow unit retirements to be primarily driven by their economics. These units can now contribute towards compliance requirements, if it is least-cost to do so, in a way that is more consistent with the System Optimizer framework than PacifiCorp's in-house tool. Synapse assumed that the Dave Johnston units 1-4 retired at the end of their book life, as well, to establish consistency with realistic expectations about the plant's operational usefulness in the existing portfolio at 2027. Other units that reach the end of their economic life after 2027 are not forced into retirement.

As shown in Figure 4, below, this adjustment advances the retirement of Hunter 2 by one year, to 2021.

[14] Due to time and expense limitations, Synapse made the simplifying assumption that capital expenditures two years prior to retirement could be avoided, but not expenses in earlier years. A more advanced version of this might include evaluating the merits of specific capital expenditures relative to the timing of the retirement decision.

Figure 4. Generation capacity by year: Alternative IRP with 1) endogenous retirements, 2) mass-based CPP compliance (low CO_2 price), and 3) adjusted decommissioning costs



2.4 Lower Renewable Energy Costs

The capital costs for renewable energy, specifically wind and solar, in PacifiCorp's System Optimizer model are not indicative of commonly held costs for these technologies. PacifiCorp includes a range for new wind builds at $2135-$2188/kW and new solar builds at $2546-$2829/kW (see Table 1). In addition, there is no new wind added to PacifiCorp's system in its 2015 IRP, and very little solar (7 MW in Oregon in 2016). The combination of these two facts calls into question whether new renewable energy is being excluded from the Company's IRP due to its high costs. To test this hypothesis, Synapse modeled alternative capital costs for both new wind and solar technologies, as recommended by Utah Clean Energy (UCE).

Table 1. Alternative wind and solar resource capital

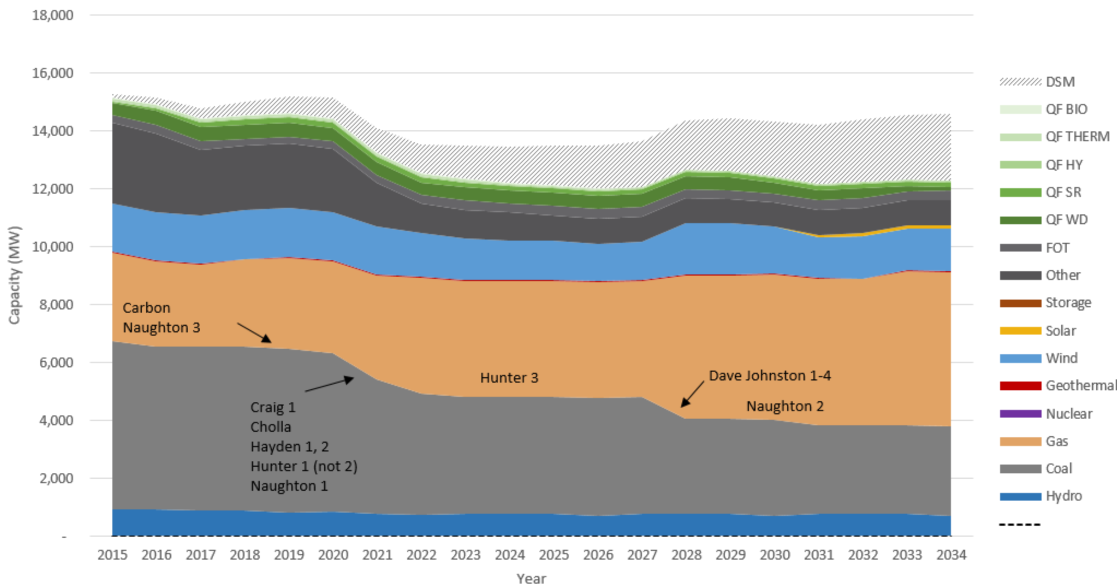
PacifiCorp's (PAC) Resource Assumptions (IRP Table 6.1)	Capacity	PAC's Capital Cost	UCE Recommended Capital Cost [1,2]
Wind			
2.0 MW turbine 29% CF WA/OR	100 MW	$2,135/kW	$1,747/kW
2.0 MW turbine 31% CF UT/ID	100 MW	$2,188/kW	$1,800/kW
2.0 MW turbine 43% CF WY	100 MW	$2,156/kW	$1,768/kW
Solar			
PV Poly-Si Fixed Tilt 26.5% CF	50.4 MW	$2,546/kW	$1,717/kW
PV Poly-Si Single Tracking 31.6% CF	50.4 MW	$2,702.kW	$1,873/kW
PV Poly-Si Fixed Tilt 25.4% CF	50.4 MW	$2,659/kW	$1,830/kW
PV Poly-Si Single Tracking 29.2% CF	50.4 MW	$2,829/kW	$2,000/kW

[1] *Wind values are based on US DOE Wind Vision Report, Chapter 2, pages 12-13, available at: http://www.energy.gov/sites/prod/files/wv_chapter2_wind_power_in_the_united_states.pdf.*
[2] *Solar values are based on IHS Outlook for US Solar PV Capital Costs and Prices, 2014–2030 / October 2014.*

To test the impact of the updated renewable energy costs, Synapse applied the costs provided by UCE as incrementally lower $/kW costs to a modified version of the case described above, with endogenous retirements, mass-based CPP compliance through a low CO_2 price, improved decommissioning costs, and assumed phase-out of the Dave Johnston plant in 2028. Applying the improved renewable energy costs to the previous case with a forced retirement of the Dave Johnston units (1-4) in 2028 was important: new wind farm opportunities are possible and economic at the Dave Johnston brownfield site. The case Synapse models continues to select no new renewable energy until either Dave Johnston retirement is forced or new transmission is added.

Overall, improved renewable energy costs do not untangle the layers of constraints PacifiCorp has included in its application of System Optimizer for its IRP. Even highly economic wind and solar fails to replace even new gas and existing coal (see Figure 5), suggesting that there are additional constraints beyond those identified here. Results show that under the current underlying structure of PacifiCorp's System Optimizer model, Wyoming is represented as highly transmission constrained between all nodes, and from Wyoming to Utah and Idaho. It is unclear if this constraint alone limits new renewable additions.

Figure 5. Generation capacity by year: Alternative IRP with 1) endogenous retirements, 2) mass-based CPP compliance (low CO_2 price), 3) adjusted decommissioning costs, 4) improved wind and solar capital cost assumptions, and 5) forced Dave Johnston 1-4 retirement in 2028



3. CONSTRAINTS IN THE SYSTEM OPTIMIZER MODEL

System Optimizer is a highly complex modeling structure that allows extensive flexibility, yet also allows layers of constraints to dictate outcomes. PacifiCorp's use of the System Optimizer model layers in multiple overlapping constraints, some of which are not readily apparent. The model generally allows users to modify the model through scenarios, which have a different meaning in the System Optimizer framework than in common IRP parlance. Scenarios in the System Optimizer model are specific adjustments that cover any form of change in the model, from costs to transmission options, buildout constraints, or operational constraints.

To create an IRP scenario (i.e., 5a-3Q, the Preferred Portfolio), PacifiCorp layered nearly 20 scenarios covering transmission changes, market price changes, Regional Haze scenarios, CPP compliance options, system updates, and various other constraints in the system. These scenarios may (and often do) overlap and negate each other, making it difficult to track at any given time the series of constraints that may either prevent or require specific units to be built or retire. For example, PacifiCorp applies a number of "technology groups" to various scenarios, which individually limit cumulative and annual wind and solar buildout. These are overlaid with other scenarios that also limit or eliminate completely buildout options. Scenarios that eliminate or limit transmission are layered with scenarios that change when units are retired, and scenarios that impart (or remove) emissions costs. Ultimately, modifying PacifiCorp's System Optimizer model requires significant knowledge of the model, a detailed mapping of the scenarios and their meaning, and significant time. It is certainly possible, or even likely, that in our short engagement, we did not find all of the relevant constraints that prevented the System Optimizer model from creating a reasonable buildout.

4. SUMMARY RESULTS

We summarize total costs and emissions for each of the cases explored by Synapse, and compare them to the Company's Preferred Portfolio. In the tables below, the cases are identified as:

A) Endogenous Retirements + Low CO_2 Price (Mass-based CPP Compliance) (**Section 2.2**),

B) Endogenous Retirements + Low CO_2 Price (Mass-based CPP Compliance) + Improved Decommissioning Costs (**Section 2.3**), and

C) Endogenous Retirements + Low CO_2 Price (Mass-based CPP Compliance) + Improved Decommissioning Costs + DJ 1-4 Retires 2028 + Utah Clean Energy Recommended Renewable Costs (**Section 2.3**).

These cases correspond to the sub-sections in Chapter 2, as noted. All of the cases considered reduced emissions below the PacifiCorp Preferred Portfolio. CO_2 emissions in the Preferred Portfolio could potentially comply with the final Clean Power Plan targets. If so, any over-compliance could generate credits that could be sold to other parties, within the states in which PacifiCorp operates or beyond. Therefore, the correct CO_2 price is one that correctly represents regional compliance, and not necessarily the one that produces the exact mass reductions required by PacifiCorp alone.

The Synapse team used the reference case regional haze scenario, a conservative emissions scenario designed to comply with possible Regional Haze requirements, assuming reasonable BART retrofits (i.e., PacifiCorp does not prevail in its Wyoming litigation to roll back the requirements). The resulting state-by-state NOx and SO_2 emissions are well below the Preferred Portfolio, and serve to demonstrate that the Synapse scenarios are also likely to comply with Regional Haze requirements.[15]

[15] PacifiCorp did not implement changes in NOx and SO_2 emissions rates associated with the various Regional Haze Scenarios, and thus the SO model does not track NOx and SO_2 emissions correctly. Thus, to generate state-by-state NOx and SO_2 emissions, we mapped unit-specific heat input SO results to unit-specific NOx and SO2 emissions rates from PacifiCorp-provided workpapers.

Table 2. Summary of emissions in PacifiCorp Preferred Portfolio and Synapse cases

Emissions	PAC Preferred	Case A	Case B	Case C
Total CO_2 (Mt)	878	865	832	826
Total NOx (Kt)	551	552	515	514
Total SO_2 (Kt)	546	500	491	486

In reporting costs, we have included the PVRR both with and without the costs of CO_2 allowance purchases. The logic is that CO_2 pricing could be simply an internal dispatch adder that PacifiCorp uses to adjust dispatch, without actually incurring costs to consumers. Similarly, CO_2 revenues could be returned directly back to customers in rebates, or used (as in RGGI) to offset energy efficiency or renewable energy programs, thus effectively remaining "inside" the system. Either way, we see these largely as transfer payments that would not be reflected in the overall system costs.

A large part of the differences in costs between the Synapse scenarios and the PacifiCorp Preferred Portfolio is the assumption of reference case regional haze assumptions. This case is conservative with regards to compliance, and installs SCR's on five more units than assumed under Regional Haze 3, the assumptions used in the Preferred Portfolio. Overall, the Reference Case has over $730 million (NPV) of capital costs that are not incurred in Regional Haze Scenario 1, but accomplishes significantly deeper reductions.

Table 3. Summary of costs in PacifiCorp Preferred Portfolio and Synapse cases

Costs (M$ NPV)	PAC Preferred	Synapse Case A	Synapse Case B	Synapse Case C
PVRR (2015-2034)	$28,095	$36,233	$36,363	$36,323
PVRR (CO_2 cost excluded)	$28,095	$28,137	$28,678	$28,720
Difference from PAC Pref.		$42	$541	$583

5. Discussion and Conclusions

The Synapse System Optimizer analysis considered a number of improvements to allow the model to better optimize decisions in the face of planning constraints faced by PacifiCorp. Our runs considered endogenous retirements, a major PacifiCorp omission, as well as alternative means of CPP compliance and sensitivity to renewable cost assumptions.

The endogenous retirement sensitivity demonstrated clearly that the units chosen by PacifiCorp for retirement under the Preferred Portfolio are not necessarily the most cost-effective units to retire under a more flexible approach. Hunter, Huntington, and Naughton all appeared potential candidates for retirement, but were not explored in the PacifiCorp's IRP.

Implementing Clean Power Plan compliance via a mass-based approach proved to be a more transparent and easily optimized planning process than PacifiCorp's in-house compliance tool. When coupled with endogenous retirements, this resulted in distinctly different retirement trajectories than PacifiCorp's Preferred Portfolio. While both the Preferred and Alternative Plans could potentially comply with the final CPP, allowing more flexibility allows a broader array of planning decisions and uses the model as it was designed for: to find least-cost planning solutions.

By forcing units to retire based on *a priori* assumptions, PacifiCorp's IRP process violates basic principles of least-cost resource planning, and represents a major step backwards from the significant progress made by PacifiCorp in its 2013 IRP.

CERTIFICATE OF SERVICE

I hereby certify that on this 28th day of August, 2015, I caused to be served the foregoing amended SIERRA CLUB'S COMMENTS ON PACIFICORP'S 2015 IRP upon all party representatives on the official service list for this proceeding via electronic mail.

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Dated this 28th day of August, 2015 at San Francisco, CA.

/s/ Alexa Zimbalist

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