ELLEN F. ROSENBLUM
Attorney General

FREDERICK M. BOSS
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

January 10, 2014

Attention: Filing Center
Public Utility Commission of Oregon
3930 Fairview Industrial Drive SE
P.O. Box 1088
Salem OR 97308-1088
puc.filingcenter@state.or.us

Re: *In the Matter of PACIFICORP, dba PACIFIC POWER, 2013 Integrated Resource Plan*
PUC Docket No.: LC 57
DOJ File No.: 330030-GN0100-13

Enclosed for filing with the Commission today are an original and five copies of the Final Comments of Oregon Department of Energy in the above-captioned matter.

Sincerely,

Renee M France
Senior Assistant Attorney General
Natural Resources Section

Enclosures
RMF:jrs/#4897302
(Electronic copies only)
c: LC 57 Service list

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 57

In the Matter of	)	
	)	
PACIFICORP, dba PACIFIC POWER,	)	FINAL COMMENTS OF
	)	OREGON DEPARTMENT OF ENERGY
2013 Integrated Resource Plan	)	
	)	

Oregon Department of Energy (ODOE) appreciates the opportunity to further comment on PacifiCorp's 2013 integrated resource plan (IRP). ODOE's final comments cover five issues: 1) carbon dioxide (CO_2) risk analysis, 2) capacity credits for solar and wind generation, 3) demand response, 4) energy storage, and 5) water use at thermal generation plants.

1. CO_2 RISK ANALYSIS

A. Summary of Recommendations

ODOE stands by the conclusions of its Opening Comments. The Commission should find that this IRP does not comply with IRP Guideline 8a of Order No. 08-339. It should instruct PacifiCorp that its next IRP should analyze the Oregon 2050 CO_2 reduction goal applied to the U.S. or the Cancún agreement signed by the U.S., whichever is more restrictive of U.S. CO_2 emissions. For this IRP, the Commission should carefully scrutinize all action items in the action plan that might have been shown to be too risky had a more appropriate range of possible carbon policies been used in the IRP risk analysis. Finally, the Commission should instruct PacifiCorp that "credible proposals by governing entities" includes adopted plans and actions by other democratically-elected sovereign states.

B. The IRP Does Not Comply With IRP Guideline 8a

To reduce the risk of costly errors, IRP guideline 8a requires a careful assessment of "compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities."[1] PacifiCorp's Reply Comments fail to show that its filed IRP complied with this guideline.

First, PacifiCorp's Reply Comments fail to address ODOE's argument that credible proposals by governing entities include the Organization of Economic Cooperation and Development (OECD) estimate of the carbon prices implied by the 2010 Cancún agreement, to which the U.S. is a signatory.[2] The OECD estimate of the carbon prices should have been used as part of PacifiCorp's carbon risk analysis.

Second, in response to ODOE's comment that PacifiCorp should provide an analysis of the carbon price necessary to achieve Oregon's greenhouse gas reduction goals as an economy-wide goal for the U.S., PacifiCorp states that it did "not have access to an economy-wide modeling tool."[3] The Western Climate Initiative conducted an economy-wide carbon pricing analysis in 2008-2010.[4] PacifiCorp was aware of this study as shown by its filed comments of August of 2008.[5]

Further, PacifiCorp states that an economy-wide analysis of Oregon's CO_2 reduction goal might yield a similar or lower carbon price than its analysis of the same CO_2 percentage reduction goal for the power sector alone. ODOE rebuts PacifiCorp's statement below and maintains its position that "an economy-wide [carbon] price will be higher than the price to achieve the same level of reduction from the power sector alone."[6] PacifiCorp's IRP analysis shows that a CO_2 price of $92 per ton of CO2 (2013$) applied to the power sector only in 2032 would reduce its 2032 power emissions by about 60 percent compared to a case with a CO_2 price

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[1] IRP Guideline 8a in OPUC Order No. 08-339.

[2] ODOE Opening Comments at 8-10 and 15-16.

[3] PacifiCorp Reply comments at 80.

[4] Western Climate Initiative Updated Economic Analysis of the WCI Regional Cap-and-Trade Program, July 2010, available at: http://www.westernclimateinitiative.org/document-archives/Economic-Modeling-Team-Documents/2010-Economic-Analysis/Updated-Economic-Analysis-of-the-WCI-Regional-Cap-and-Trade-Program/.

[5] See the comments under "PacifiCorp" at http://www.westernclimateinitiative.org/economic-modeling.

[6] ODOE Opening Comments at 5.

of $18 (2013$).[7] We know from experience in Europe and the U.S. that a $92 per ton carbon price level for the transportation sector (the equivalent of a one dollar increase in the price of a gallon of gasoline) would yield much less than a 60 percent reduction in transportation emissions.

ODOE's Opening Comments cite the experience in Europe.[8] As additional evidence, note the weak response of U.S. gasoline use to the huge increase in the price of gasoline from 2000 to 2012. The U.S. average retail price of motor gasoline was $1.52 per gallon in 2000. The average for 2011 and 2012 was $3.63, more than two dollars greater.[9] This is more than a one dollar increase in real terms. Yet, 2012 sales of motor gasoline were slightly higher than in 2000,[10] as opposed to the 60 percent decrease that would be expected if motor gasoline sales were as responsive as the electric sector to carbon prices.

Further evidence comes from the analysis by the Western Climate Initiative in 2010. This study shows that a widely applied carbon price of $33 per metric ton of CO_2 in 2020 would reduce power sector emissions 20 percent below the reference case while it would reduce economy-wide emissions only 8 percent.[11] This result indicates that achieving a specific percentage reduction economy-wide would require a substantially higher price than the price to achieve the same reduction in the power sector alone.

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[7] Based on a comparison of the 2032 emissions of CO2 for case C01 in Figure 8.11 with emissions for case C18 in Figure 8.13 of PacifiCorp IRP Vol. I at 212.

[8] ODOE Opening Comments at 5-6.

[9] See Appendix 4, graph of retail gasoline prices by year. Available at: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMM_EPM0_PTE_NUS_DPG&f=A.

[10] See Appendix 5, graph of supplied gasoline by year. Available at: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mgfupus1&f=a. This table refers to "U.S. Product Supplied of Finished Motor Gasoline." This is the amount of gasoline supplied to distributors which "Approximately represents consumption of petroleum products" (see "product supplied" definition at http://www.eia.gov/dnav/pet/TblDefs/pet_sum_snd_tbldef2.asp). The basic difference between retail sales at gasoline stations and product supplied is changes in the inventory held by distributors which are fairly steady year to year.

[11] Western Climate Initiative Updated Economic Analysis of the WCI Regional Cap-and-Trade Program, July 2010, Table 17 at 51. Available at http://www.westernclimateinitiative.org/document-archives/Economic-Modeling-Team-Documents/2010-Economic-Analysis/Updated-Economic-Analysis-of-the-WCI-Regional-Cap-and-Trade-Program/.

PacifiCorp speculates that "a regulatory construct that allows for the use of cross-sector domestic and international greenhouse offsets *could* lead to an economy wide regulation that yields a lower CO_2 price outcome than an alternative regulation that covers only the power sector of the U.S. economy."[12] (Emphasis added.) The company provides no rationale for why future economy-wide regulations would allow for greenhouse gas offsets but power sector-only regulations would not. ODOE cannot see any reasons why offsets are more likely under economy-wide regulations. There is no justification for this inconsistent assumption between the two cases.

A consistent[13] analysis would reliably demonstrate that a higher carbon price is needed under economy-wide carbon regulations to achieve a given percentage reduction target than achieving the same percentage reduction in the power sector if regulations are placed on the power sector alone. While both the power sector and other sectors have the option of increased energy efficiency, the power sector has more and lower cost options for switching to less carbon-intensive resources (coal to natural gas, and natural gas to renewable resources) than do the transportation sector or stationary end-use sources.

While there are fuel-switching options for these other sectors (to low-carbon fuels for transportation and from oil to gas for end users) these options are more expensive or less available than for the electricity sector.

Finally, ODOE asks that the Commission clarify that, in addition to credible plans by the federal government and each of the U.S. States, the definition of credible proposals by governing entities includes ***adopted plans and actions*** by other democratically-elected sovereign states.[14] PacifiCorp notes that there are many factors affecting greenhouse regulations that differ between the U.S. and other governing entities.[15] However, these differences would be more than

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[12] PacifiCorp Reply comments at 80-81.
[13] "Consistent" in this context means regulations that achieve the same percentage reduction with consistent assumptions between the two scenarios.
[14] ODOE Opening Comments at 18.
[15] PacifiCorp Reply Comments at 81.

counterbalanced by including only plans that are being put into action (and excluding mere proposals by non-U.S. governing entities).

C. IRP Guideline 8a Applies to PacifiCorp, Regardless of Considerations Discussed in the Company's Reply Comments

PacifiCorp's Reply Comments discuss the collaborative nature of its IRP process.[16] While Order No. 08-339 clearly values collaboration,[17] nothing in the order implies that discussions of a range of forecasts – from subscription services to the use of input from stakeholders – relieves a utility of its responsibility to comply with Guideline 8a. PacifiCorp is responsible for complying with all of the Commission's IRP guidelines. Similarly, satisfying the trigger point analysis required under Guideline 8c[18] does not relieve PacifiCorp of the need to satisfy Guideline 8a. In addition, whether any stakeholder openly challenged PacifiCorp with a specific credible proposal from a governing entity during the preparation of the IRP does not prevent parties from identifying such proposals to the Commission in this proceeding. It is the utility's responsibility to research credible proposals. ODOE would be stunned to learn that PacifiCorp was unaware of the 2010 Cancún agreement or that the company did not know that Oregon's statutory goal applies economy-wide.

PacifiCorp's Reply Comments discuss how its IRP analysis satisfies the trigger-point analysis required under Guideline 8c.[19] The company also discusses its risk analysis using only the lowest three of its five carbon price scenarios. PacifiCorp opines that it "would not expect that further analysis of even higher CO_2 prices, as seen in the hard cap CO_2 price scenarios would alter [its] near term Action Plan ..."[20] This kind of linear extrapolation is inconsistent with the results of IRP cases C14 and C18, the cases with the higher hard cap CO_2 prices. Under

[16] PacifiCorp Reply Comments at 79-80
[17] OPUC Order No. 08-339 at 18.
[18] IRP Guideline 8c in OPUC Order No. 08-339 requires that the utility identify at least one CO_2 compliance scenario that would trigger a portfolio substantially different from the preferred portfolio, develop a portfolio for that scenario, assess the likelihood of that scenario and compare the expected costs and risks of the two portfolios.
[19] PacifiCorp Reply Comments at 30-31.
[20] PacifiCorp Reply Comments at 30.

the hard cap scenarios, PacifiCorp's System Optimizer model created portfolios that were substantially different from any of portfolios created under the "High" CO2 price. Further, these two portfolios were also substantially different from each other. It is unreasonable for PacifiCorp to assert that a risk analysis that included these two higher price scenarios would not be instructive. In addition, even the higher carbon price of these two scenarios is not high enough to comply with Guideline 8a. In any case, a trigger-point analysis under Guideline 8c is not a substitute for the requirements of Guideline 8a.

D. Why Compliance With Guideline 8a Is Important

PacifiCorp's most serious error is when it states that it will have "multiple opportunities to re-evaluate its CO2 price assumptions before and after the issuance of proposed [EPA] regulations in June 2014."[21] While it is true that PacifiCorp will be able to "reevaluate [then] current market conditions"[22] as it prepares its 2015 IRP, it will not be able to undo capital investments that it has made between now and then. That is precisely why the Commission adopted Guideline 8a. Only by carefully assessing risks ***before the investments are made*** will the IRP process be able to meet the Commission's goal of a "selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[23] To accomplish this goal requires a careful assessment of "compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities."[24]

2. CAPACITY CREDITS FOR WIND AND SOLAR

A. Summary of Recommendations

PacifiCorp states that it "will consider Staff's recommendation to compare the capacity contribution of wind and solar resources between alternative methods."[25] ODOE appreciates this

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[21] PacifiCorp Reply Comments at 19.
[22] Ibid.
[23] IRP Guideline 1c in OPUC Order No. 07-002.
[24] IRP Guideline 8a in OPUC Order No. 08-339.
[25] PacifiCorp Reply Comments at 74.

commitment. However, it does not go far enough given the large impact assignment of capacity credit has for resource selection and utility IRP action plans. ODOE stands by the recommendations in its Opening Comments [26] on how the Commission should instruct PacifiCorp in its methods to determine the capacity contribution of variable energy resources.

B. Determining a Reasonably Accurate Capacity Contribution for All Resources

Approximations of capacity contribution should only be used if they are shown to be reasonably accurate and where a correct analysis is too expensive for routine application. PacifiCorp's Reply Comments do not demonstrate that its approximation is accurate. Nor has the company shown that it is too expensive to conduct an Effective Load Carrying Capacity (ELCC) analysis using 8,760 hours per year.

PacifiCorp's method of valuing the capacity contribution of variable renewable generation is only an *approximation* of the correct statistical analysis. PacifiCorp uses only the highest 100 load hours. Capacity contributions estimated with this method are invariant to the level of variable resources on the utility's system. As PacifiCorp adds increasing amounts and different types of variable energy resources, the capacity contribution of each new resource changes and a loose approximation becomes increasingly inappropriate. See Appendix 1, section 1. An ELCC analysis of all resources would provide accurate and consistent estimates of the capacity contribution for all resources.

C. Response to PacifiCorp's Defense of Its Current Method

The capacity contribution of a variable energy resource in a portfolio depends on the characteristics of the other resources in the portfolio and the shape of loads throughout the year. For example, as the share of load served by a variable energy resource increases, the capacity contributions from additions of this resource decline. See Appendix 1, section 1. PacifiCorp calculates the capacity contribution for wind and solar using only the output during the 100 highest load hours. Under this method the estimated capacity contribution is unaffected by the

[26] ODOE Opening Comments at 20.

share of load served by a variable resource. Further, the company's current method calculates the capacity contribution of each variable energy resource in isolation, rather than taking into account other resources and load shapes.

ODOE is not suggesting that one method be used to calculate the capacity credit for renewable resources and a different method be used for non-renewable resources. ODOE specifically recommends that "PacifiCorp conduct a stochastic capacity credit study that fully uses 8,760 hours of data per year and provides consistent levels of reliability, as measured by unserved energy, ***across portfolios***" (emphasis added).[27] Portfolios include both renewable and non-renewable resources. Such a statistical analysis would provide estimates of the capacity contribution of non-renewable as well as renewable resources.

ODOE acknowledges that PacifiCorp's current method may have been adequate when the company had low levels of variable energy resources on its system. What has changed over time is the complexity of PacifiCorp's system. The company now has substantial wind resources in addition to major legacy hydro resources. It will likely add significant amounts of solar resources within the 20-year planning horizon. The company's historical method to estimate the capacity contribution of hydro, wind and solar resources in isolation is no longer an adequate representation of their impact on the reliability of PacifiCorp's system. It is time for PacifiCorp to adopt a statistically correct analysis of 8,760 hours of loads and resources. While an ELCC analysis may add a small amount of cost to the planning studies, even a tiny increase in the cost of serving load that may result from incorrectly valuing the capacity contribution of certain resources would outweigh any increased cost of studies.

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[27] OPUC Order 07-002. Guideline 11 states in part, *"Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios.... Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives."*

D. Why the Reliability Analyses in the Current Plan Do Not Reasonably Address Variable Resources

PacifiCorp's Reply Comments discuss how loss-of-load probability (LOLP) and energy-not-served analyses are conducted to evaluate final portfolios.[28] The Company is correct that LOLP is essentially the same method as used to calculate ELCC. Unfortunately, portfolios with substantial renewable resources tend to be screened out before final analysis. Capacity is the key resource metric used in the System Optimizer model. Because all portfolios are produced by the System Optimizer, portfolios with substantial renewable resources never make it to the final LOLP and unserved energy analyses, even though these portfolios might be a better combination of expected costs and risk.

3. DEMAND RESPONSE

A. Summary of Recommendations

PacifiCorp's 2013 IRP Action Plan should include a Class 1 Demand Side Management (DSM) pilot in Oregon, and the Commission should direct PacifiCorp to conduct more detailed analyses of demand response opportunities in future IRPs consistent with IRP Guideline 7 of Order No. 07-002, which states, "Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities)."

B. Background

Class 1 DSM resources include direct load control, scheduled irrigation and thermal energy storage. The demand response resources captured under Class 1 DSM are a valuable tool to manage load curves and spikes, displace costly reserves, maintain system flexibility and integrate variable energy resources.

[28] PacifiCorp Reply Comments at 73-74.

In its 2011 IRP, PacifiCorp committed to acquiring at least 140 MW of Class 1 DSM resources by 2013.[29] PacifiCorp also committed to implementing a commercial curtailment project that included customer-owned standby generation opportunities, if cost effective, by 2012.[30] However, the preferred portfolio in the 2013 IRP does not contain any Class 1 DSM until 2027. In addition, PacifiCorp cancelled the commercial curtailment project due to a revised load forecast that, according to the company, suggested direct load control is not cost-effective.

Not all Class 1 DSM options may be immediately cost-effective for PacifiCorp. ODOE supports a staged approach to advance PacifiCorp's technical capabilities to use demand response technologies. PacifiCorp can then best discern the most cost-effective approaches and report on those findings in its next IRP.

C. PacifiCorp Should Conduct a Class 1 Demand Response Pilot

ODOE recommends that PacifiCorp pursue a Class 1 DSM pilot in Oregon and at least one other state before filing its next IRP. ODOE does not have a specific recommendation on a capacity target for the pilot at this time. But PacifiCorp's current proposal to have zero Class 1 DSM resources for over a decade, with no plan to evaluate these resources further, is insufficient.

D. PacifiCorp Should Conduct More Detailed Demand Response Analysis in Future IRPs

ODOE supports NW Energy Coalition's request in its Initial Comments that "the Commission encourage the Company to increase the amount and sophistication of its overall analysis regarding demand response and other load control tools in the next IRP."[31] Utilization of load control capabilities should be evaluated for their potential to reduce customer energy costs over the long-term.

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[29] *In the matter of PacifiCorp 2011 Integrated Resource Plan*, Docket LC 52, Order No. 12-082 at 5 (March 9, 2012).
[30] PacifiCorp 2011 IRP revised action plan.
[31] NW Energy Coalition LC 57 Initial Comments at 7–8.

4. ENERGY STORAGE

A. Summary of Recommendations

PacifiCorp's IRP Action Plan should include an energy storage pilot comprised of a suite of demonstration projects, and the Commission should direct PacifiCorp to provide a more comprehensive treatment of energy storage in future IRPs.

B. Background

In its last IRP action plan, PacifiCorp committed to an energy storage demonstration project in Utah. In May 2012, PacifiCorp reported its partnership (as Rocky Mountain Power) with EMB Energy on a flywheel pilot. The report stated that the proposed size of the project had shrunk from 100 units totaling 25 MW of capacity to 10 units totaling 2.5 MW.[32] In its 2013 IRP, PacifiCorp stated that "[d]ue to lack of supplier funding, in 2013 this project is no longer being pursued by PacifiCorp."[33]

PacifiCorp did commission a 2011 HDR Engineering study "on incremental capacity value and ancillary service benefits of energy storage. … The scope of the study was to develop a current catalog of commercially available and emerging large, utility-scale and distribution scale energy storage technologies as well as define respective applications, performance characteristics and estimated capital and operating costs for each technology."[34] The IRP suggests that the results of the report were incorporated into the System Optimizer tool, which helps select resources for IRP portfolios.[35] The 2013 IRP does not recommend further actions on energy storage.

C. PacifiCorp Should Conduct an Energy Storage Pilot

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[32]See Appendix 6 –EMB Development and Demonstration at Rocky Mountain Power, May 29, 2012. Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/RMP-EMBDevelopment_FlywheelDemoProjectUpdate-May2012.pdf

[33] PacifiCorp 2013 IRP at 254.

[34] Ibid.

[35] We note that Commission IRP guidelines require equal treatment of supply-side resources and expressly include storage. "All resources must be evaluated on a consistent and comparable basis… All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and **storage** – and demand-side options which focus on conservation and demand response…." Commission IRP Guideline 1a from Order No. 07-002 (emphasis added).

PacifiCorp should not only renew its commitment to an energy storage pilot, but it should approach these demonstrations programmatically. An excellent example is Duke Energy. Duke Energy installed small-scale systems of variable types, sizes, and applications across its multi-state system to learn more about how well each application worked and integrated with its system.[36] The utility's premise is that current trends lead toward greater energy storage applications: technologies will mature, cost-benefit ratios will improve, and customers will continue to build customer-sited generation. The utility needed to demonstrate energy storage systems in order to understand and then maximize their value.

For at least these same reasons, PacifiCorp should take a similar approach with relatively low cost and low risk. In order to be meaningful, the pilot should incorporate several applications of energy storage system-wide, dispersed or co-located depending on the testing opportunity. In California PUC's energy storage docket, three classes of storage emerged: customer-sited units, distribution-level applications, and transmission-connected units for bulk storage, generation-based units or frequency regulation.[37] The California PUC ultimately designed its procurement targets around these three classes after considering several "use cases," or applications for energy storage in each of these categories. These use cases illustrate the range of applications and benefits of storage, scaling from functional grid management and large-scale variable generation integration down to customer-level resiliency, including critical infrastructure. These applications all apply to PacifiCorp's system and should be instructive as the company designs its own program.[38]

Rather than set a specific capacity value ceiling, PacifiCorp's energy storage pilot should test a range of applications that are most meaningful to its system. ODOE recommends at least

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[36] Duke Energy's Energy Storage Projects presentation November 13, 2013, as part of the Clean Energy States Alliance State & Federal Energy Storage Technology Advancement Partnership (ESTAP) Webinar series. Available at http://www.cleanenergystates.org/assets/Uploads/Duke-Energy-Storage-Webinar-Presentations-11.13.13.pdf

[37] California Public Utilities Commission Rulemaking 10-12-1007. See http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm.

[38] See in particular the Electric Power Research Institute's *Cost-Effectiveness of Energy Storage in California* (June 2013), http://www.cpuc.ca.gov/NR/rdonlyres/1110403D-85B2-4FDB-B927-5F2EE9507FCA/0/Storage_CostEffectivenessReport_EPRI.pdf.

deploying energy storage in conjunction with a distribution system substation and testing a utility-controlled storage application behind a customer's meter. In addition, PacifiCorp should open the doors to energy storage technologies in a competitive process. This will give PacifiCorp information about the state of the competitive market.

The 2013 IRP action plan should include a commitment by PacifiCorp to install a suite of demonstration projects across PacifiCorp's system and report results in the next IRP.

D. Treatment of Energy Storage in Future IRPs

Future IRPs should offer a more comprehensive treatment of energy storage. Storage is a unique resource that does not fit neatly into existing categorizations, and the evolving regulatory framework through FERC is presenting new market opportunities. PacifiCorp should be prepared to report in future IRPs on energy storage advances and opportunities to incorporate storage technologies into its portfolio as a flexibility and reliability tool.

5. WATER USE AT THERMAL GENERATION PLANTS

A. Summary of Recommendations

ODOE recommends three water-related actions for the 2013 IRP.

- First, we recommend that the Commission set an expectation that future IRPs will report comprehensively on significant water issues directly associated with plant operations, risk assessments and risk management techniques to avoid water conflicts within the fleet.[39] This report should discuss opportunities to insulate ratepayers from the risk of heavy reliance on water supplies, including upgrades that are not simply the result of a federal requirement. PacifiCorp also has other means to reduce risk from reliance on water, including investing in other supply-side resources."

[39] PacifiCorp already evaluates investments and upgrades at coal facilities to reduce water consumption and use, outside of compliance obligations. See for example, Water Usage Reduction Study Report, October 13, 2013, included as Appendix 2, provided by PacifiCorp in response to ODOE DR 12-14. This report was commissioned to "evaluate the feasibility and cost of water usage reduction strategies and technologies at their Huntington Unit 2 power plant and, by comparison at their Jim Bridger Unit 3 power plant;" and describes a suite of upgrades that PacifiCorp could install, with associated cost and capacity impacts. PacifiCorp's plans as a result of this study are unclear, or whether these costs were modeled associated with the resource under the IRP.

- Second, we recommend that the Commission direct PacifiCorp to incorporate into its portfolio model reasonable cost estimates of anticipated compliance and water management upgrades at existing facilities that are either required on any timeframe or anticipated within the next ten years.
- Third, we support PacifiCorp's decision to incorporate dry cooling as a standard measure for new gas units and its provision in the Action Plan to consider water availability as a key factor for siting new gas units.[40]

B. Background

PacifiCorp owns or has a stake in coal and natural gas facilities across the West: facilities with significant water demands in states -- Wyoming, Colorado, Arizona, and Utah – with known and serious water constraints.

A power supply system with minimal reliance and impact on water resources will be more resilient, less risky, and cost less to operate in the long-term. ODOE believes that regardless of whether water has been a significant issue in the past, it will certainly be in the future – and the IRP should reflect that growing importance.

- In November 2013, the National Association of Regulatory Utility Commissioners (NARUC) passed a resolution that acknowledges that "[w]ater-related constraints to generation plants can reduce electricity supplies, threaten reliability and increase costs" and resolves to "[u]rge States and federal authorities to recognize the important role of water supply and related risks in making sound power supply investment decisions and the need to properly identify and allocate water-related risks and benefits."[41]

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[40] PacifiCorp 2013 IRP, Vol. I, Action Item 2: Intermediate/ Base-load Thermal Supply-side Resources 2014-2016 at 255.

[41] *Resolutions Passed by the Committee of the Whole at the 125th Annual Meeting of the National Association of Regulatory Utility Commissioners, November 20, 2013*, Resolutions ERE-2 and WA-2 at 12. http://www.naruc.org/Resolutions/13-1120-1116am-vz-Resolution-Packet-HRS-edits-afterbd-mtg.pdf#13.

- The U.S. Senate held a hearing on the topic of drought and reliability in the electric sector in April 2013.[42]
- According to the Environmental Protection Agency, "[s]team electric power plants alone contribute more than half of the toxic pollutants discharged to water bodies by all industrial categories currently regulated in the Unites States."[43]

C. PacifiCorp Should Improve IRP Reporting and Evaluation of Water Quality and Quantity Issues for its Existing and Proposed Thermal Fleet

Regulators may be concerned with water constraints if thermal facilities are operating in a watershed that has a recent history of low water years or near drought conditions, operating with junior water right claims, or operating where the discharge waterbody has high sensitivity to temperature and toxic metals. All of these conditions create risk and limit operational reliability.[44] Even where there is not a demonstrated history of water constraints, future climate scenarios anticipate increasing pressure on water supplies, higher temperatures, and reduced availability of freshwater for all demands across the West.

PacifiCorp's fleet raises a unique set of issues for Oregon. PacifiCorp's Oregon customers, through their rates, are underwriting facilities that have impacts in other states. Oregonians' expectations about unit operations and environmental stewardship cannot be met through state regulation. While these concerns are outside of the typical IRP review, these plants' reliance on water increasingly has cost and risk impacts to Oregon ratepayers that are directly of concern to the Commission.

One ratepayer impact is facility upgrades and their costs. From PacifiCorp's responses to ODOE's data requests, it is clear and not surprising that PacifiCorp has devoted significant

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[42] U.S. Senate Energy and Natural Resources Committee hearing, "Exploring the Effects of Drought on Energy and Water Management," April 25, 2013. http://www.energy.senate.gov.
[43] http://water.epa.gov/scitech/wastetech/guide/steam-electric/proposed.cfm
[44] In its IRP, PacifiCorp indicates that EPA's new environmental regulations, including cooling water intake regulations, could "limit operations, change dispatch, and could ultimately determine the economic viability of PacifiCorp's coal-fueled generation assets." PacifiCorp 2013 IRP Vol. 1 at 33. However in response to our data request, PacifiCorp indicates no anticipated operational impacts associated with cooling water intake regulations. PacifiCorp response to ODOE DR 12, Part (a), included as Appendix 3.

attention to water consumption and use at their plants and to proposed federal regulations that will result in expensive upgrades in the next few years. These costs are not complicated forecasted carbon prices – these costs are very real upgrades to operating units.

IRP portfolio cost modeling should not be limited to significant federal rulemakings that are final or nearly so; the modeling should incorporate reasonable estimates of anticipated compliance and water management upgrades within the next ten years, or required upgrades that will occur on any timeframe. For example, PacifiCorp incorporated into its model the cost of compliance with one significant federal rulemaking (cooling water intakes under Clean Water Act Section 316(b)) but did not model the cost of compliance with another rulemaking (new industry toxic discharge guidelines) that is scheduled to conclude in 2014. While there may be unknown variables in terms of exact federal requirements, modeling zero cost is clearly the wrong number.

Another ratepayer impact is the risk in setting requirements for new facilities, namely natural gas facilities. PacifiCorp's baseline for modeling most new gas plant resources presumes dry cooling, although it acknowledges a preference for wet cooling due to performance and efficiency, if costs allow.[45] PacifiCorp's initial instinct is sound -- the company should maintain a dry cooling assumption for all gas units in future IRPs. In addition, PacifiCorp can take

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[45] PacifiCorp 2013 IRP Vol. I at 131.

advantage of WECC and other regional models that now incorporate water availability to identify locations that offer the lowest conflict water opportunity in confluence with its own development needs.

DATED this 10th day of January, 2014.

Respectfully submitted,

ELLEN F. ROSENBLUM
Attorney General

Renee M. France, OSB #004472
Senior Assistant Attorney General
Attorney for the Oregon Department of Energy

Presented at ASES 2010 Annual Conference,

QUANTIFYING THE COST OF HIGH PHOTOVOLTAIC PENETRATION

Richard Perez
ASRC, 251 Fuller Rd
Albany, NY, 12203
Perez@asrc.cestm.albany,edu

Thomas E. Hoff
Clean Power Research
Napa, CA 94558
tomhoff@cleanpower.com

Marc Perez
Columbia University
New York, NY 10020
mjp2167@columbia.edu

ABSTRACT

This paper presents a methodology to quantify the cost of energy storage required to provide firm capacity on a utility power grid using a combination of energy produced by a specific generation source and storage. Firm capacity is defined to mean that all demand above a given threshold load is satisfied exclusively by the considered generation source, directly or indirectly via storage. The cost of storage is representative of the cost of high penetration since the approach is valid over all penetration levels. The paper applies the methodology to PV as the generation source for three utility case studies. Results suggest that the cost of storage is a small fraction of the installed PV cost up to penetration levels approaching 40% in the best cases.

1. INTRODUCTION

An important benefit of PV generation is its ability to satisfy peak electrical demand [1, 2, 3]. Much of the value of dispersed PV generation, including generation capacity credit, transmission and distribution (T&D) stress mitigation, and grid security enhancement, derives from this effective capacity.

Effective capacity decreases with PV penetration. While peak demand is often indirectly driven by the solar resource via heat waves and resulting air conditioning demand, the secondary peaks and base load demands are not. The result is that dispersed PV generation's peak-shaving ability decreases with increasing penetration. It is important to note, however, that environmental, fossil fuel depletion/price risk mitigation and economic development values are not necessarily a function of penetration.

This paper quantifies the amount and cost of storage required to maintain firm capacity with any level of penetration. The methodology is flexible enough to analyze any penetration level from 0% to 100%.

The methodology is generally applicable to any type of generating resource, intermittent or dispatchable. In order to clearly illustrate how to apply the methodology, however, PV is selected as the generating resource under consideration.

2. METHODOLOGY

This section begins with a definition of variables. The relationship between the variables is illustrated in Fig. 1 using measured load and simulated PV data.

2.1 Definitions

Peak Load: L_{Peak} (MW) is the peak system load over the selected analysis period

Threshold Load: $L_{Threshold}$ (MW) is the system load above which all demand is satisfied by the considered generation resource, either directly or indirectly using storage.

Base Load: L_{Base} (MW) is the load below which power cannot be displaced. It can be expressed as a fraction (γ) of the Peak Load.

Firm Generation Capacity: G_{Firm} (MW) equals Peak Load minus Threshold Load. All loads greater than the Threshold Load are satisfied by energy produced from the considered generation resource, either directly or indirectly using storage. For example, a system with a 1,000 MW Peak Load and an 800 MW Threshold Load has Firm Generation Capacity of 200 MW.

Installed Generation Capacity: $G_{Installed}$ (MW) is the rated capacity of the installed generation.

Useful Generation Capacity: G_{Useful} (MW) is the rated capacity of a resource that would provide the same amount of energy as $G_{Installed}$ after accounting for all storage and/or excess production losses (see below).

Excess Energy Production (MWh) is the excess energy that must either be stored or wasted. Energy produced by base load generation, such as nuclear power, cannot be displaced. Thus, Excess Energy Production occurs when the Base Load exceeds Load minus Production.

Storage capacity is composed of power Storage Power Capacity (MW) and Storage Energy Capacity (MWh).

Storage Power Capacity: $S_{Power\ Cap.}$ (MW) is the maximum power output of storage required at any time during the analysis period to ensure a selected firm capacity objective. The Storage Power Capacity can range between a minimum of 0 (if no storage is ever required) and a maximum of Firm Generation Capacity (if storage is required to make up for a total deficit of the resource at the time of the Peak Load).

Storage Energy Capacity: $S_{Energy\ Cap.}$ (MWh) is the maximum storage production capacity required at any time during the analysis period.

Note that the storage is sized to achieve firm capacity and not to absorb all possible Excess Energy Production. All excess production beyond the ability of the capacity-sized storage to absorb it is considered lost.

Two ratios are useful in performing the analysis: Firm Capacity Penetration and Relative Firm Capacity.

Firm Capacity Penetration: α equals the ratio of Firm Generation Capacity to Peak Load.

$$\alpha = \frac{G_{Firm}}{L_{Peak}} \tag{1}$$

Relative Firm Capacity: β is the ratio of Firm Generation Capacity to Installed Generation Capacity.

$$\beta = \frac{G_{Firm}}{G_{Installed}} \tag{2}$$

There is a limiting factor in the maximum possible value of β in the case of PV generation. Relative Firm Capacity can easily reach 100% or greater at modest penetration levels. The only requirement to provide Firm Generation Capacity is that storage is sufficient to backup PV when needed. As Firm Capacity Penetration increases, the requirement that PV produce enough energy to satisfy all loads above Threshold Load becomes relevant. This may limit the maximum possible value of Relative Firm Capacity.

Consider a simple example of PV achieving 100% Firm Capacity Penetration on a grid with a 50% load factor, and a PV generation resource with a 25% capacity factor. Generating enough energy with PV to satisfy all demand would require $G_{Installed}$ to be twice as large as the L_{Peak} (assuming no conversion losses into and out of storage). As a result, Relative Firm Capacity could not exceed 50%.

Equations (1) and (2) can be combined so that Installed Generation Capacity is expressed as a function of Peak Load, Firm Capacity Penetration, and Relative Firm Capacity.

$$G_{Installed} = \left(\frac{\alpha}{\beta}\right) L_{Peak} \tag{3}$$

2.2 Cost of Providing Firm Generation Capacity

The cost of providing Firm Generation Capacity can be calculated as the sum of three terms: (1) the capital cost associated with the storage investment, (2) the capital, fuel, and O&M costs associated with needing to oversize the resource to account for round-trip storage efficiency losses and (3) the capital, fuel, and O&M costs associated with needing to oversize the resource to account for excess energy losses.

$$C_{Total} = C_{Storage} + C_{G-Roundtrip} + C_{G-Excess} \tag{4}$$

In the case of PV, the considered costs are installation costs and do not include lifetime operating costs, to the exception of $C_{Storage}$ where the discounted cost of future replacements is included depending upon the technology choice (see case studies below).

C_{Total} may be expressed per kW of $G_{Installed}$, G_{Firm}, or G_{Useful}.

The cost of storage is a function of the considered storage sizes and charge/discharge time scales. Table 1 provides estimates of energy costs, power costs, discharge times, and operational sizes for current and near-future storage technologies [6].

For this article, we selected lead-acid batteries or equivalent for both short-term (less than one PV system-hour) and medium term needs (less than 10 system-hours) with an installed nominal power/energy cost of $350 per kW/ $200 per kWh for short-term requirements (<1 hour) and \$350 per kW/\$150 per kWh for 1-10 hour requirements. Batteries are assumed to have a lifetime of 10 years and must therefore be replaced. Beyond 10-hour requirements, large scale compressed air, some form of pumped hydro, or high density metal-air batteries could be considered. Hence we selected a nominal cost of \$850 per kW/\$50 per kWh, and a lifetime of 30+ years.

Both $C_{Storage}$ and $C_{GRountrip}$ depend upon storage round-trip efficiency. Based on the mix selected, we conservatively assumed a round-trip efficiency of 75% for the batteries and 65% for the large scale technologies.

The sum of $C_{G\text{-}Roundtrip}$ and $C_{G\text{-}Excess}$ is quantifiable in terms of the difference between $G_{Installed}$ and G_{Useful}, i.e., it amounts to the cost oversizing the resource and incuring production losses in order to meet the firm capacity objective. In this article we assume that the nominal resource oversizing cost for PV is \$2,500/kW – this represents the lowest cost cutting edge of today's largest scale systems, but likely a mainstream value at the time PV reaches the levels of penetration pertaining to this study.

3. CASE STUDIES

We illustrate the methodology with three utility case studies, asking the question: what is the cost of ensuring that a firm fraction of PV can satisfy all demand above a firm penetration threshold as this threshold is lowered and approaches base load?

This question is answered for the following set of assumptions:

Firm Capacity Penetration (α)	up to 75%
Relative Firm Capacity (β)	25, 50, 75 and 100%
Base Load Fraction (γ)	25%

Note that β = 75% represents the best case of low-penetration, high-value effective PV capacity observed for US utilities [e.g., 1, 2]. The selected values for α and γ imply that, at 75% Relative Firm Capacity, all loads on the utility grid are met exclusively by PV+storage and base-load generation.

The selected utilities, Nevada Power (NP), Rochester Gas and Electric (RG&E) and Portland General (PG) have markedly distinct environments and operational characteristics. Nevada Power (NP) is a metropolitan utility with a considerable solar resource and a large commercial air-conditioning load. Rochester Gas and Electric (RG&E) serves a medium-sized industrial city in upstate New York, where cloudy conditions are frequent. Portland General (PG) serves the city of Portland, Oregon. Both NP and RG&E are summer peaking utilities while PG has comparable summer and winter demand peaks, but a higher winter energy consumption overall.

For all utilities, nominal PV output was simulated for fixed systems facing southwest at 30^{o} tilt (i.e., optimized for mid-afternoon summer peak shaving). Time/site specific PV simulations were performed using SolarAnywhere and PV Simulator [4, 5]; both have been thoroughly validated [7, 8].

4. RESULTS & DISCUSSION

4.1 Achievable Relative Firm Capacity for PV

As explained in Section 2, there is a limiting factor in the maximum possible value of β for PV generation. Figure 2 illustrates this limit for the three selected utilities. For PG, β can only reach 100% up to 31% firm penetration. The maximum possible β decreases down to 28% at 75% firm penetration. For RG&E and NP, the 100% achievability limit is reached at 48% and 68% firm penetration, respectively.

Achievable Relative Firm Capacities are linked to (1) the resource's capacity factor – highest for NP; (2) the coincidence between demand and solar generation – also highest for NP -- and (3) the utility's load factor – highest for PG at 67%, and lowest for NP at 48%.

4.2 Cost of High Penetration

Storage Requirements: Figure 3 (left side) reports the required Storage Energy Capacity as a function of Firm PV Penetration for Relative Firm PV Capacity strategies of 25%, 50%, 75% and 100%.

Note that some of the curves are truncated because of the above β limit.

It is important to reiterate what the β strategies signify in order to intercompare storage requirements. At any level of Firm Penetration, a β of 25%, 50%, and 75% imply $G_{Installed}$ respectively 4, 2, and 1.33 times larger than the 100% Relative Firm Capacity case. Therefore it is not surprising that storage requirements increase with increasing β (hence decreasing $G_{Installed}$). In fact some of the β strategies do not need storage to achieve firm capacity, e.g., in the case of RG&E, the β = 25% can guarantee its firm objective without any storage up to ~10% firm penetration.

The apparent inflection points and plateaus (enhanced by the log scales used in the plots) reflect causal changes in storage requirements depending on the site and selected firm capacity strategy, first reaching the point where storage cannot be replenished within a 24 hour cycle during a multi-day peak event and then the point where storage begins to be driven by sustained winter PV output deficit.

Cost: The total cost of high penetration, including both its storage and generation oversize components is reported on the left side of Fig. 3. All costs are reported in terms of $ per G_{Firm}.

In order to present results in a context where options can be directly intercompared, the calculated costs are reported so as to answer to the following decision-making question: "What is the cost of maintaining a given low penetration PV value as penetration increases?" Further assuming that this low penetration value derives from a Relative Firm Capacity of 75% based upon [1, 2], Figure 3 reports the total cost of maintaining this low penetration capability as penetration increases for each of the four β strategies. This objective can be achieved either by adding storage as needed, or by oversizing the generator -- e.g., the β = 25% strategy will achieve this objective at the cost of an oversized array by a factor of 3, while the β = 100% strategy will achieve it with an undersized array (i.e., delivering a benefit) but at the possible cost of more storage.

As firm penetration increases, the tradeoffs between the strategies become apparent. At low penetration, the lowest firm capacity costs is achieved for the highest β, but as penetration increases, the least cost options switch to lower and lower β, as the cost of storage overtakes the cost of oversizing the generator.

The cost of high penetration per se, starting from the low penetration ideal case (defined here as 75% PV capacity) is the low boundary tangent to the network of curves highlighted in the plots with the thick semi transparent curve.

4.3 Bottom Line

Considering a target relative firm capacity of 75% (representative of high-value low penetration) penetration costs remain well under $100 per firm kW up to firm penetrations of 18%, 13% and 5% for NP, RG&E and PG, respectively. For these respective utilities, cost reaches $1,000 per firm kW for penetrations of 28%, 20% and 11%, and $3,000 per firm KW for penetrations of 44%, 40% and 18%.

Significant firm capacity PV penetrations can thus be achieved for both NP and RG&E while incurring manageable logistical expenses. For instance in the case of RG&E, representing a typical northeastern utility (and by extension, much of the northeast power grid), 20% firm penetration could be achieved at a cost of $1,100 per firm kW with a β=75% strategy, amounting to a cost of $825 per installed PV kW ($835 per useful PV kW) i.e., an extra levelized 4.5 cents per generated PV kWh. This represents a small fraction of the low penetration value that PV can deliver for New York's ratepayers/taxpayers which has been estimated at upwards of 30 cents per kWh for metropolitan northeastern utilities [e.g., 9].

The poorer solar-load synergy in the PG territory tends to limit the economically viable penetration domain to more modest values.

It is however important to note that these results are based upon locally dispersed PV generation. Local generation strongly exploits local load-solar synergies up to 35-40% penetration in the best case. At very high penetration, the seasonal solar output deficit of locally based generation becomes the main cost driver.

Therefore higher penetration levels could be better served with either geographically decentralized PV generation (e.g., the type of continental deployment envisaged projects like Desertec [10]); or by exploiting seasonal synergies with other renewables, such as wind generation that can mitigate seasonal deficits. In addition, the solar geometry, selected here to maximize peak-matching, does become non-ideal at very high penetration when seasonal deficit becomes the dominant storage cost driver, hence optimizing PV geometry as a function of penetration may be advisable. Finally, load management and efficiency gains focusing on the periods of low solar resource (particularly lighting and heating loads) could substantially increase the economically viable penetration domain.

It is our intension to apply the methodology developed here to explore/optimize these very high penetration options in a continuing phase of this research.

5. CONCLUSIONS

The most important result of this study is that considerable firm PV capacity can be achieved at a modest integration cost up to significant resource penetration. The low-penetration value of PV, including its capacity, grid security, and distributed benefits, in addition to its non-penetration dependent environmental, fuel depletion and economic growth benefits, can be maintained at a manageable expense until local dispersed PV generation becomes a considerable part of the generation mix. For instance, a state such as New York should be capable of absorbing and benefiting from well over 7 GW of -high-value PV without having to incur significant integration costs beyond the cost of PV itself, further noting that the storage sizes involved could well be met with a smart deployment of interactive plug-in transportation.

At very high penetration, integration costs escalate exponentially, and the study suggests that other solar deployment logistics should be considered including, continental-scale deployments, pairing with other renewables, solar geometry optimization maximizing winter output, and demand optimization minimizing off-season requirements. Nevertheless, the low-cost penetration potential is large enough to allow for the development of a considerable localized, high-value PV generation market worth 100's of GW in the US.

The present conclusions are of course dependent upon both the considered storage choices and costs, and the considered cost of the PV resource. Thermochemical hydrogen and flow-batteries could hypothetically reduce large-volume storage costs much further than assumed here [11] and push the high-value local PV generation potential well beyond the penetration range identified here.

Finally, while we focused on the issue of achieving firm capacity via storage, it is important to recognize that we did not take in account the very short-term fluctuations of the solar resource, an important penetration-related issue which will also require mitigation [12] addressable via storage. However, it may not be overly speculative to state that, as penetration increases the short term fluctuations from a dispersed PV fleet will tend to mitigate [13] and could be handled by a small fraction of the storage dedicated to firm capacity.

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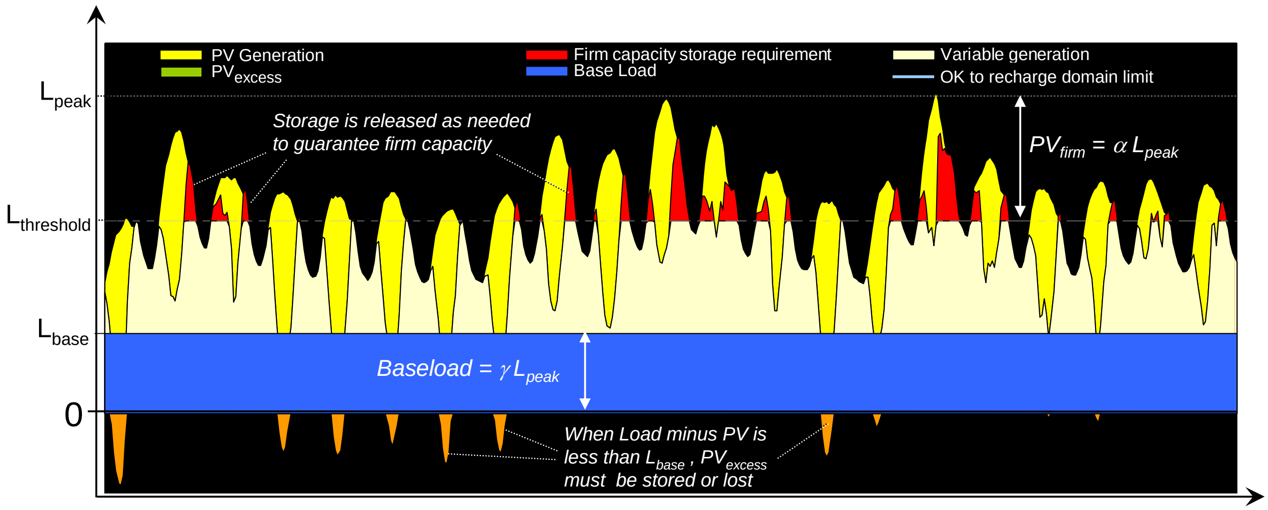

Figure 1: Illustrating the interrelationship between the study's variables with a 21-day peak demand period in Rochester Gas & Electric

TABLE 1
Cost, efficiency and time scale of current and prospective energy storage technologies (source [6])

Technology	Capital Cost per Unit Power ($/kW)	Capital Cost per Unit Energy ($/kWh-output)	Efficiency (without power electronics) --> %	Discharge Time (hr)
High-Power Electrochemical Capacitors	100 - 500	4000 - 10000	96 - 99%	0.0001 - 0.01
Long-Duration Electrochemical Capacitors	200 - 600	100-200		
Long-Duration Flywheels	3000 - 10000	1000 - 3000	90 - 96%	0.001 - 0.8
High-Power Flywheels	200 - 600	2300 - 4600		
CAES + gas	500-1000	28 - 100	70 - 79%	1.3 - 30+
Pumped Hydro	600 - 1500	30 - 130	70 - 85%	10 - 100+
Flow Batteries	700 - 2600	100 - 1300	72 - 85%	1 - 30+
NaS	1000 - 2300	200 - 900	85 - 90%	4 - 10
Li-Ion	1100 - 3800	600 - 2800	93 - 98 %	0.1 -16
Ni-cd	600 - 1200	700 - 2200	60 - 67%	0.02 - 10
Lead-Acid	300 - 800	190 - 1000	72 - 76%	0.01 - 10
Metal-Air Batteries	900 - 2000	20 - 50	43 - 50%	10 - 100+
Hydrogen (hydrolysis + ICE)	600 - 800	10 - 40	35 - 40%	1 - 100+
Hydrogen (hydrolysis + fuel cell)	800 - 2000	5 - 25	55 - 70%	0.1 - 100+

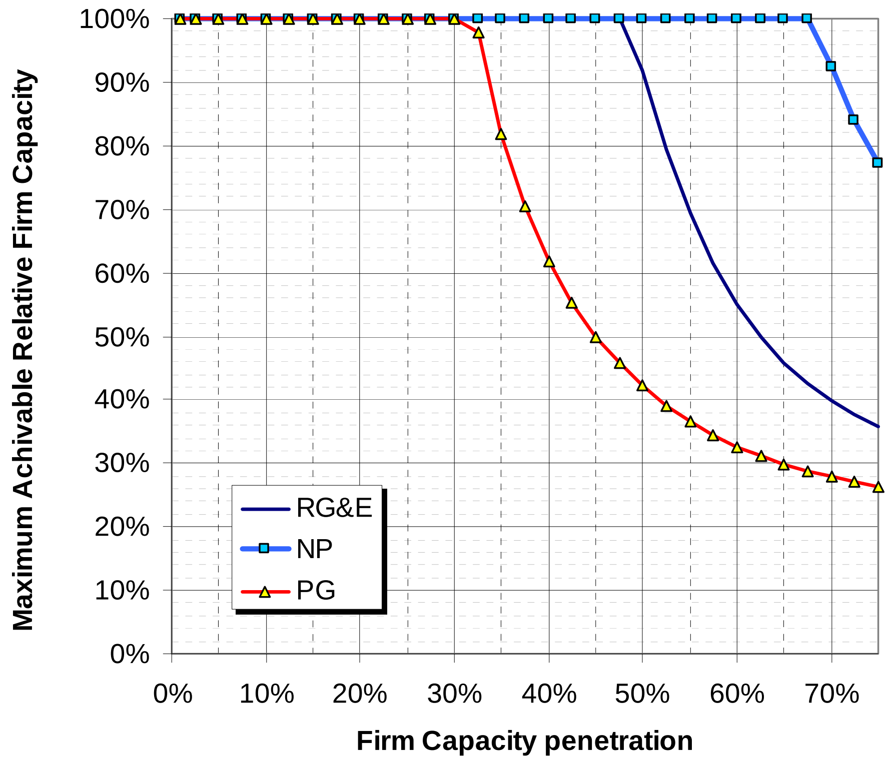

Figure 2: Achievable Relative Firm Capacity of PV Generation as a Function of Firm Penetration

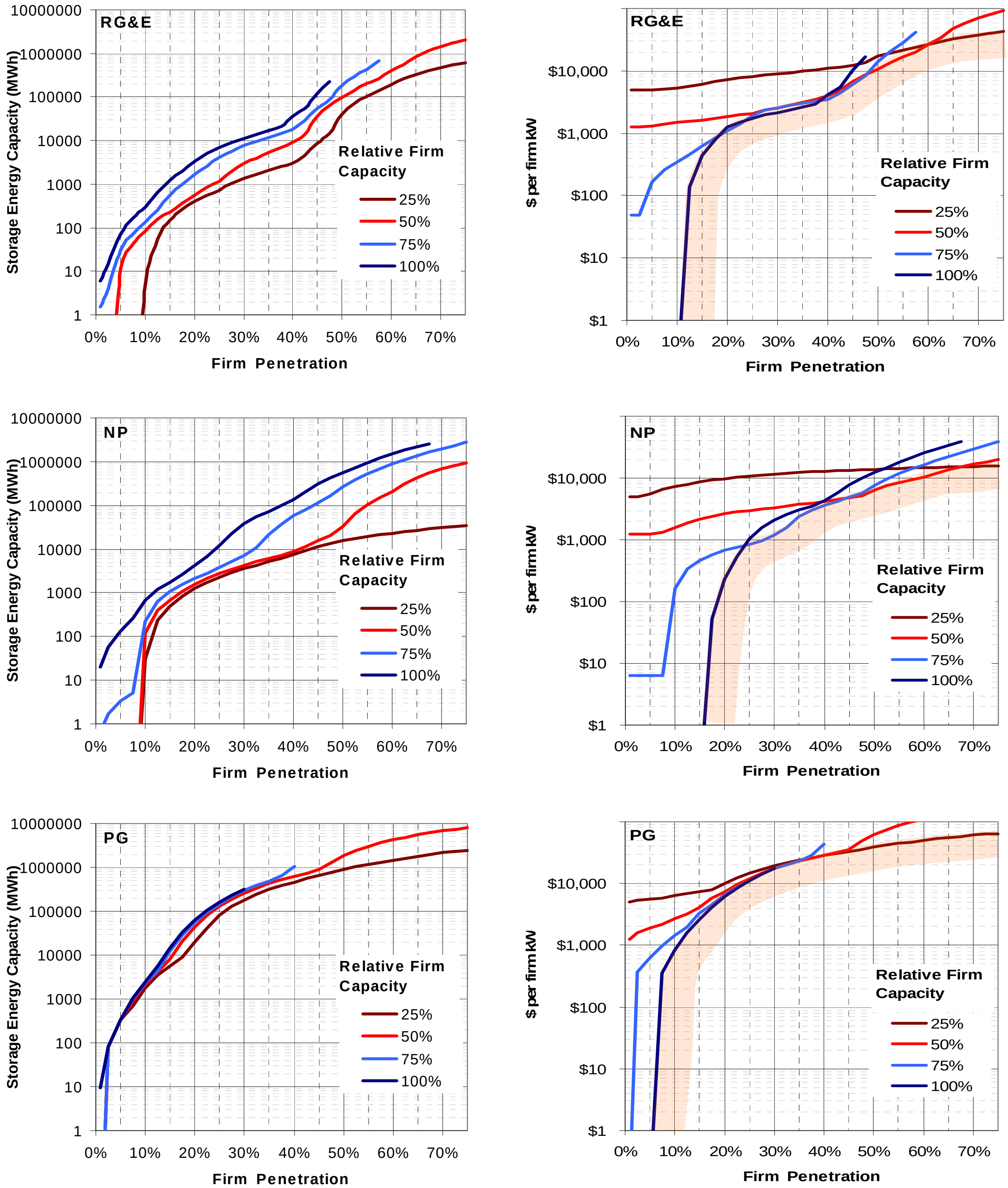

Figure 3: Energy Storage Requirements (left) and cost (right) necessary to maintaining a low-penetration firm capacity of 75% as a function of firm PV penetration. Costs are reportred in terms of $ per firm kW delivered.

LC-57/PacifiCorp
October 31, 2013
ODOE Data Request 12

ODOE Data Request 12

Cooling Water Intakes: Under the Clean Water Act Section 316(b), the Environmental Protection Agency (EPA) plans to publish final rules placing new requirements on cooling water intakes for facilities that use more than two million gallons per day. The rules are scheduled to be published in the Federal Register in November 2013 and will address impingement, entrainment, and intake velocities. As noted in Vol. I, page 4 under Existing Coal Resources, PacifiCorp incorporated environmental requirements into its portfolio modeling, including these new rules. PacifiCorp also indicates that several plants would be subject to the new rules: Dave Johnston, Jim Bridger, Naughton, Gadsby, Hunter, Carbon and Huntington [page 39].

PacifiCorp also acknowledges the significance of all of EPA's proposed rules: "[E]ach of these regulations will have a significant impact on the utility industry and could affect environmental control requirements, limit operations, change dispatch, and could ultimately determine the economic viability of PacifiCorp's coal-fueled generation assets." [pages 32-33].

(a) Please provide a description of equipment upgrades or adjusted operations that are anticipated at each affected plant to meet the new cooling water intake rules.
(b) What is the estimated cost of those upgrades or operation changes?
(c) What is the anticipated timeframe for installing these upgrades or making operation changes?
(d) Which of the costs in subpart (b) above were in which of the PaR model runs?

Response to ODOE Data Request 12

(a) Actual equipment upgrades and/or operational adjustments, if any, at affected facilities will be contingent upon the final Clean Water Act (CWA) Section 316(b) rule. The proposed rule would require cooling water intake structure impingement studies at all 316(b)-affected facilities listed in the Company's response to subpart (b) below, with additional entrainment studies required at the Dave Johnston plant which utilizes once-through cooling. PacifiCorp's review of the proposed rule indicates that modification of the intake structure debris screens at affected facilities may be required to provide compliance with the proposed rule's maximum intake water velocity standard. PacifiCorp does not anticipate needing to implement operational changes that would affect dispatch of the affected plants to comply with the proposed rule.

(b) The following confidential table summarizes PacifiCorp's initial estimated 316(b) proxy compliance costs (pending future studies and final compliance requirements).

Water Usage Reduction Study Report
Final

Prepared by Stone & Webster, Inc., a CB&I Company
9201 East Dry Creek Road
Centennial, CO 80112

October 18, 2013

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TABLE OF CONTENTS

1. Executive Summary

PacifiCorp requested Stone & Webster, Inc. (SWI) to evaluate the feasibility and cost of water usage reduction strategies and technologies at their Huntington Unit 2 power plant and, by comparison at their Jim Bridger Unit 3 power plant. A review of existing technologies that could significantly reduce water usage at each plant pointed to the use of either new, wet-dry cooling towers or alternately, the use of fin-fan heat-exchangers (coolers) installed in series with the existing cooling towers. Both options would reduce water usage by approximately 34 to 35 percent however the wet-dry cooling tower retrofit would cost significantly less than the option of installing suitable fin-fan coolers: approximately $38.7 to $90.3 million[1] versus $64.6 to $151 million[2] for the wet-dry cooling towers and fin-fan coolers respectively. Additionally, annual maintenance would be significantly lower with the wet-dry scenario versus the fin-fan cooler option: annual costs would increase between $960 thousand and $2.2 million for the wet-dry cooling tower installation versus the fin-fan approach which would add approximately $2.7 and $6.3 million to the annual maintenance budget. Capacity would be reduced slightly more, approximately 1.5 percent versus 0.3 percent, with the fin-fan approach due to its higher fan horsepower requirements with a corresponding increase in heat rate.

2. Introduction

Water has always been an issue in the western United States. Existing water supplies vary from year to year but with the exception of man-made infrastructure such as reservoirs and pipelines, generally have remained fairly static over time. Against this backdrop, the population of the west has steadily increased and shows every indication of continuing to increase in the future. Water usage for residential and farming activities continues to increase every year along with water usage for power generation. According to the Utah Division of Water Resources "In 2005, Utah ranked second highest (in per-capita water use in the nation) with a rate of 260 gallons per capita per day (gpcd) consumed (behind Nevada 280 gpcd)"[3]. With a static water supply and ever increasing demand, at some point in the future demand will attempt to outpace supply.

This report is divided into three main categories: First a general description of various plant water usages and reduction strategies is provided to assist power generation management in identifying and implementing incremental water savings measures, and second, a somewhat more in depth look at two water savings approaches that could, using today's technology, be implemented at the Huntington Unit 2 power plant to reduce water usage by approximately 35-percent. Finally, a narrative section tabulates the main differences between Huntington Unit 2 and the Jim Bridger Unit 3 plant in Wyoming and how those differences can impact water savings approaches.

Note that this is a relatively high level report which should be used as a basis for further, more detailed study of water savings options at the subject power plants. It is not intended to provide high accuracy cost or benefit data, only to identify the most promising alternatives. Further, the most promising alternatives for these power plants appear to be relatively expensive and may only make sense if water supplies are forecasted to become critically low.

[1] Note that all estimated costs presented in this report are plus or minus 40-percent, hence the large cost ranges. For example, an estimated cost of $100 would be presented as "between $60 and $140" rather than simply $100.
[2] These ranges correspond to an accuracy range of ±40-percent for the estimated cost to implement each option.
[3] Municipal and Industrial Water Use in Utah, Utah Division of Water Resources, Salt Lake City, Utah, December 29, 2010.

3. Discussion of Current Water Usage and General Usage Reduction Scenarios

Plant water usage data for purposes of this report is a combination of actual plant data and data from similar units that SWI has experience. We believe that it provides a representative picture of actual plant usage and therefore can be useful in predicting water savings opportunities.

As with any large coal-fired power plant that does not use once-through cooling, the Huntington Unit 2 plant employs a cooling tower to reject Rankine cycle waste heat. SWI estimates that the total cooling tower water usage is approximately 4,500 gallons per minute, depending on plant load and weather conditions. The following table, Table 1 illustrates the approximate water usage at a typical power plant of approximately 450 MW capacity[4]:

Plant Water User	GPM	% Dist
Material Handling - Dust Control	75	1.29
Site Roads Dust Control	30	0.52
Coal Pile Run-off Sumps to Evaporation Pond	8	0.13
Cooling Tower Blowdown and Evaporative Losses	4,500	77.42
Bottom Ash and Pyrite Dregs to Landfill	75	1.29
Water Treatment Filter Cake to Landfill	8	0.13
Water Treatment System Brine to Evaporator	75	1.29
Aux Steam Drains (recovered in Condenser)	15	0.26
HP-IP Steam Drains (recovered in Condenser)	8	0.13
LP Steam Drains (recovered in Condenser)	8	0.13
Boiler Drains (recovered in Condenser)	15	0.26
Floor, Hub, Area Drains to Evap Pond	15	0.26
Lime/Limestone Prep	750	12.90
Gypsum Cake and Hydrates to Landfill	225	3.87
Potable Water, Sanitary, Lab Sinks, Waste	8	0.13
Total Estimated Water Losses	5,813	100.00

As is apparent, the majority of a typical coal fired power plant's water usage is the result of evaporation and blow down to facilitate cooling tower heat rejection. Of the 4,500 gpm water usage listed "Cooling Tower Blowdown and Evaporative Losses", the evaporative losses would be approximately 4,125 gpm combined with approximately 375 gpm in blow down, assuming an operational "Cycles of Concentration" goal of 12[5].

[4] Data not provided by PacifiCorp, this is an estimate based on other similarly sized power plants and may not accurately reflect water usage at either Huntington of Jim Bridger.

[5] Where COC = M/(M-E) where M is the total makeup water volume for the cooling tower and E represents the evaporative losses. Note that we used a value of 12 for the COC which is the ratio of the concentration of chlorides

Regardless of the blow down versus evaporative loss ratio, the installation of dry cooling technology to either totally or partially replace the plant's evaporative heat rejection will reduce total cooling tower water usage in direct proportion to the amount of dry heat rejection to total heat rejection. In other words, if half of the plant's heat rejection were accomplished through the use of dry cooling technology, the cooling tower water usage would be cut in half to 2,250 gpm. The following sections discuss other, incremental means of reducing water usage. However this report's primary mission is to explore means to reduce this "heat rejection" water usage and therefore focuses on that aspect of plant operation.

a. Plant Efficiency (heat rate) Improvement

Increasing plant efficiency means increasing the amount of energy being sent to utility customers and/or decreasing the amount of energy being sent up the stack or out the cooling tower. In other words, higher plant efficiency translates to reduced water usage for a given plant output.

Unfortunately, increasing plant efficiency is not a trivial exercise. An inspection of the thermodynamic temperature versus entropy diagram for a Rankine cycle power plant reveals that by increasing system temperature and pressure, cycle efficiency increases and therefore water usage decreases. However, retrofitting an existing power plant to operate at higher pressures and temperatures would be prohibitively expensive. Most of the plant's steam pipes would require replacement as would the steam turbine and the boiler. In effect, a new power plant would be required.

A less expensive option would be to closely maintain the operational and technical items at the plant that contribute to efficiency and at the same time restructure plant personnel training and incentive programs to move efficiency closer to the collective consciousness of everyone working at the plant. Items suggested on DOE's web site[6] include but are not limited to:

1. Identify, implement, and train workers in best practices,
2. Incentivize plant operators or employ a dedicated plant efficiency engineer,
3. Optimize processes using advanced computational tools,
4. Conduct on-line, real-time performance monitoring of efficiency,
5. Standardize performance metrics,
6. Reduce air, water, steam and flue gas leakage,
7. Test and replace seals on air heaters, condensers, boilers, and tube components if they are found to be leaky,
8. Maintain all heat exchange surfaces in a clean, non-fouled state,
9. Upgrade steam turbines, including dense pack blading, redesigned seals, and improved exhaust blading design to minimize exhaust losses and maximize generation.
10. Use variable speed motors where possible,
11. Lower stack temperature, i.e. increase boiler efficiency,

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in the circulating water to the concentration of chlorides in the cooling tower makeup water and was the value provided by PacifiCorp.

1. [6] Improving the Thermal Efficiency of Coal-Fired Power Plants

12. Use low-grade heat for coal drying,
13. Install flue gas condensing heat exchangers, see above
14. Implement intelligent soot blowing systems

Most of the above list was originally published in the U.S. Department of Energy *Technical Workshop Report*, "Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States", February 24 & 25, 2010.

b. Dry Cooling (Air Cooled Condensers [ACC], both hybrid and 100-percent ACC)

If space is available, another option to increase dry heat rejection (cooling) capacity is to install an Air Cooled Condenser (ACC) in parallel with the existing wet condenser (hybrid cooling system) or as a stand-alone heat rejection system (100-percent ACC). An ACC unit consists of a series of tubes that steam passes through with forced draft air blown over the outside tube surfaces. The ACC units are run continuously while the cooling tower is relegated to rejecting heat from the Auxiliary Circulation Cooling water system or the Main Circulation Cooling water system depending on ambient temperature and humidity. The deciding range for running the different heat rejection systems (assuming an ACC and the existing wet condenser/circulating water/cooling tower system are employed) is typically 45°F - 55°F (dry-bulb) to maintain condenser vacuum. Below 45 to 55°F dry-bulb temperature the ACC can generally satisfy plant heat rejection requirements. At the transition point, control of evaporation heat rejection can be accomplished by shutting down cooling tower cells sequentially. Above approximately 45 to 55°F the circulating water cannot reject enough heat to maintain sufficient vacuum at the turbine exhaust. Once this happens the turbine loses efficiency and therefore capacity.

An ACC deck for this application would require significant space and costs would likely be significantly above the cost to install "fin-fan" coolers. As described below, fin-fan coolers are units where circulating water from the existing condenser is routed through tubes with atmospheric air blown over them to remove heat. Conversely, an ACC has gases on both sides of the heat transfer media. Steam would flow inside the tubes and air would flow over them. For this reason, significantly more heat transfer area is required with an ACC as compared to an equal amount of cooling using fin-fan coolers. Additionally, turbine exhaust steam is considerably less dense than liquid water therefore large diameter ducts would be necessary to convey the steam from the turbine exhaust to the ACC units. Because the ACC's represent a separate steam condensing technology, the existing condenser would require either complete removal, replacement or significant modification as would the steam turbine exhaust outlets[7]. This is because the existing condenser is located exactly where the large diameter exhaust duct would have to exit the steam turbine and go to the ACC. Any condenser-neck-mounted feedwater heaters and associated extraction and condensate piping would also have to be replaced, relocated or re-accommodated within the new ductwork.

Final ACC design, fan operation and fan diameter requirements would be defined by a competent engineering firm or supplier. The completed system would also require electrical power, maintenance hoists, ladders, enclosures, doors, controls, valves and piping. Significant electrical modifications would be required to enable operation of the required fan motors at either constant or variable speed.

[7] Depending on the technology selected.

As mentioned above, the salient modifications involved with an ACC retrofit at the Huntington Unit 2 power plant would be the removal or significant modification of the existing condenser. The steam turbine final, low pressure stages of blading would require modification to accommodate higher back-pressures.

Currently, the performance of any power plant with a cooling tower heat rejection system is tied to the ambient wet-bulb temperature. Given the low humidity conditions prevalent in most of the western United States, wet bulb limitations are generally not an issue at Huntington.

If PacifiCorp opted to eliminate evaporative water losses entirely and installed a 100-percent ACC system, plant capacity would then be tied directly to ambient dry bulb temperature. In hotter weather, an ACC equipped power plant's capacity could be significantly diminished. On the other hand, if PacifiCorp chose to modify or relocate the existing condenser or more appropriately put in a new condenser of lesser capacity than the present one, <u>and</u> install an ACC in parallel, the plant would not lose as much capacity, water usage could be significantly reduced but not entirely eliminated and installation costs and outage time would increase significantly.

Because of the impracticality of converting and existing plant to such an arrangement, no estimate of space requirements or associated costs has been identified for this option.

c. Flue Gas Water Recovery

A new Water Research Center (WRC) is being developed by a consortium of EPRI (Electric Power Research Institute) and SRI (Southern Research Institute), with support from 14 other electric generating stations. The WRC is evaluating new plant-based research technologies. One of the areas of interest is moisture recovery from flue gas. Data collection will start summer of 2013. No data results have been published up to this point regarding the WRC efforts. Previous research was conducted in 2003 through 2006 by the Energy and Environmental Research Center (EERC)[8].

The EERC study "demonstrated the feasibility and merits of a liquid desiccant-based process that can efficiently and economically remove water vapor from the flue gas of fossil fuel-fired power plants to be recycled for in-plant use…" However, a recent literature search suggests that there is little or no commercially available technology for flue gas water vapor recovery at this time.

Because of the limited information available, no estimate of space requirements or associated costs has been identified for this option.

d. Night time cold water production for daytime circ water cooling

Thermal Energy Storage (TES) capability is gaining popularity for power plant cooling water systems as a capital cost saving solution. Capital costs are reduced by enhancing plant performance during hot weather so that new electrical capacity (i.e. a new power plant) is not necessary to meet steadily increasing system load. The premise is that thermal energy is stored as a temperature change in the storage medium. Although this technology has been applied primarily to gas turbine inlet cooling, it could be applied to condenser cooling as well.

During the night hours when load typically tapers off, the plant can cool a large body of water, say 4 million gallons for use in plant heat rejection enhancement during the day. The extra

[8] EERC, an agency of the University of North Dakota, as an account of work sponsored by the U.S. Department of Energy and Siemens Power Generation, Inc.

cooling effect imparted by the TES is translated into reduced water evaporation in the cooling tower although it is partially offset by increased power consumption during the off-peak hours to produce the cold water. Because there is more sensible heat transfer due to the cooler circulating water, less latent heat of vaporization is required and therefore less cooling tower water usage is necessary. Other benefits relating to TES include:

1. Reduced capital costs due to avoidance of the need to construct additional electrical capacity
2. Improved reliability and flexibility
3. Increased plant cooling efficiency using less expensive energy
4. Increased capacity during peak load hours
5. Expanded capabilities for simultaneous storage of fire protection water, back-up cooling water, or, alternatively, stratified hot water

The required tankage would be mild steel construction with reflective encapsulated Teflon™ paint interior and exterior, and have approx. dimensions of 110 ft diameter x 60 ft height at the Huntington site. This option would require the addition of a large scale refrigeration plant capable of supplying a significant fraction of the plant's daytime heat rejection requirements. Note that the plant will actually use more fuel but it will exhibit a greater daytime, hot weather capacity and somewhat less water use.

SWI's qualitative analysis indicates that the water saved by such a system would not likely justify the cost. Therefore, no estimate of space requirements or associated costs has been identified for this option.

e. Modified Operation Schedule

One means of saving water that requires little or no plant modification would be to operate the subject power plant only during cooler weather or at night. Plant heat rejection takes place using one of two processes: 1. Latent heat of vaporization when cooling tower water evaporates and removes approximately 1,000 BTUs per pound of water evaporated, and 2. Sensible heat transfer from the cooling water to the air within the cooling tower. Note that sensible heat transfer only removes 1 BTU per pound of water for every degree of temperature change. By operating only during cooler temperatures, a higher fraction of heat rejection would utilize sensible heat transfer rather than vaporization and specific water consumption per kWH would decrease.

This option is functionally impractical for an operating power plant. Generally speaking, plants in this part of the country see their highest loading when ambient temperatures are at their highest. The only practical means of implementing this method of water usage reduction would be if significantly more cost effective means of energy storage were available. Such cost effective energy storage technology is not currently available.

No estimate of space requirements or associated costs has been identified for this option.

f. Upgrading Boiler Efficiency

Although important to plant operation and overall efficiency, boiler efficiency does not have significant impact on heat rejection related water usage. Therefore boiler efficiency is addressed only briefly in this report.

Boiler efficiency, as measured by energy-in versus usable energy-out is affected by several factors:

1. Tube surface area,
2. Excess air,
3. Tube surface cleanliness, inside and out,
4. Preheating and preheater seal effectiveness,
5. Radiation and convective heat losses,
6. Coal mill fineness,
7. Combustion efficacy, efficiency and
8. Basic boiler and burner design considerations

While important, boiler efficiency only effects water usage in a peripheral manner therefore it is not elaborated on any further in this report.

g. Waste Water Recycling

As mentioned above, plant, non-evaporative water losses could possibly be re-used if they could be captured, partially treated and reused within the cooling tower. To do this, they would have to be cleaned up to approximately potable water standards (specifically chloride concentration and dissolved solids), likely using reverse osmosis and/or micro-filtration. Reverse osmosis could return between 50 and 75 percent of the currently estimated 375 gpm currently wasted through cooling tower blow down. While this doesn't eliminate the main water usage at the plant – evaporative losses within the cooling tower – it would represent a significant water usage savings. Another technique sometimes employed is to reuse boiler blowdown water in the SO_2 scrubbers.

4. Evaluated Means of Water Usage Reduction at Huntington Unit 2

a. Wet-Dry Cooling Tower Installation

Description: An innovative approach to enhancing cooling tower performance and reducing water usage is the addition of a 'dry' section, in front of the wet section. This is a closed circuit, indirect heat exchanger with a closed loop coil, analogous to a common auto radiator. The dry section would be installed atop the wet section and use the common draft of air drawn by the cell fan as a cooling medium. The function of the dry section heat exchangers is to perform as much sensible, non-evaporative heat transfer as possible thereby reducing evaporative losses.

A few different wet-dry cooling tower arrangements are available, but the structural implications must be resolved before renovating existing, older cooling tower cells to include new dry sections. Our cost estimate includes the installation of a completely new, replacement cooling tower (wet-dry design) in place of the existing cooling tower. It does not include demolition of the existing tower.

Modeling: The system described would reduce plant water consumption by approximately 35-percent over the course of a typical year. Note that water usage reduction would vary through the four seasons with the highest magnitude of water reduction occurring during the winter months and the lowest magnitude occurring during the hot, summer months. The modeling effort focused on maintaining plant performance more or less at its current level. The main performance reduction would be caused by the somewhat larger fans and motors required by a wet-dry cooling tower as compared to a conventional cooling tower. Appendix 1 provides a summary of SWI's modeling activities.

Performance: Note that the new wet-dry unit would have 13 cells with 250 HP fans in each cell. The electrical power required for such a system would be approximately 2.4 MW during peak conditions. The existing cooling tower likely requires approximately 1.2 MW during peak conditions therefore this plant will only gain approximately 1.2 MW in plant loads, or 8,900 MWH annually, a loss of approximately 0.3 percent.[9] Heat rate should remain approximately the same with this modification except that there would be somewhat more fan horsepower required which might degrade heat rate slightly.

Possible Installation Layout: Figure 1 provides a proposed layout, roughly to scale illustrating how a wet-dry cooling tower could be installed at the Huntington Plant.

Figure 1, Huntington Illustrating Proposed Location of new 48 by 625 Foot long Wet-dry Cooling Tower with 13 Cells, each with 250 HP Fan and Motor

Estimated Cost: A complete replacement of the existing cooling tower with a wet-dry tower is estimated to cost of approximately $38.7 to $90.3 million, including engineering, procurement, construction, testing and commissioning.

b. Water to Air Heat Exchangers (Fin-Fan Coolers) in Series with a Wet Cooling Tower

Description: As alluded to above, fin-fan coolers consist of water-to-air heat exchangers where the fluid to be cooled, circulating water from the existing condenser, flows through heat exchanger tubes while ambient air is blown over them, i.e. again, similar to a scaled-up automobile radiator. As mentioned above, this type of heat exchange process requires less surface area than an equivalent ACC because rather than being a gas-to-gas heat transfer process,

[9] Assumes 3,350,800 MWH annual generation including 85% availability and 450 MW peak capacity.

fin-fan coolers are a liquid-to-gas process which is significantly more efficient. The addition of fin-fan coolers are more of a modification to the existing system rather than a complete replacement and are, therefore, less costly than a comparable ACC installation.

Unlike the air cooled condenser (ACC) retrofit described above, no modifications to the existing condenser would be necessary nor would there be any need to modify the steam turbine exhaust ducting or blading configurations. The fin-fan coolers could be operated alone with the wet cooling tower isolated or bypassed until the return circulating water temperature is too high to maintain the required condenser vacuum. In other words, if return circulating water were too hot, the cooling tower would be employed. If on the other hand, air temperature was cool enough the fin-fan coolers could be employed with great effect to conserve water. While this mode of operation would save the most water, it is probably the least efficient, requiring the most fan power. Additionally, the circulating water pump design conditions would have to be reviewed. Replacement of the impellers, or the entire pump(s) would need to be evaluated.

Modeling: Modeling used to estimate the square footage of heat transfer area required to obtain a 34-percent water usage reduction also suggested that as with the wet-dry cooling tower, water usage would be reduced significantly more during the winter months than during hot weather. This is because sensible heat transfer is enhanced when air temperature is lower. The mechanism for water usage reduction is similar to a wet-dry cooling tower: more sensible heat exchange would take place therefore evaporative heat transfer – and water usage – would be curtailed. Appendix 1 provides a summary of SWI's modeling activities.

Performance: SWI estimates that 44 separate cells, each one approximately 48 feet square (2,325 SF each) and each served by a 200 HP fan would be necessary. The total electric load would peak at about 6.6 MW, *in addition to* the existing cooling tower horsepower requirements. This 6.6 MW load would be deducted from plant capacity directly resulting in a loss of 49,100 MWHs per year, approximately 1.5 percent. If operated properly, using the cooling tower during high temperature conditions and the fin-fan coolers during cooler weather, heat rate reduction should be minimal except that the 44 additional fans would add to the plant's required electrical load and would adversely impact heat rate.

Possible Installation Layout: Figure 2 illustrates the approximate foot print required to install suitable fin-fan coolers at Huntington. The specific shape and location would be defined during the engineering process.

An efficiency mode could also be developed that would use the wet cooling tower until the water consumption limit was being approached, at which time condenser pressure could be allowed to rise and/or the dry fin-fan coolers employed to reduce water usage.

The preferred mode of operation would depend on many factors including water availability, air temperature and humidity, turbine backpressure (condenser vacuum) limits and power output desired.

SWI's qualitative analysis indicates that the series arrangement would be preferable since the cost of large diameter bypass piping and valves would be partially avoided and the wet cooling tower would see reduced inlet water temperatures that would improve heat transfer.

Estimated Cost: SWI estimates that the approximate cost to install such a modification is approximately $64.6 to $151 million, including engineering, procurement, construction, testing and commissioning.

Figure 2, Huntington Illustrating Proposed Location of new Fin-fan Coolers, Approximately 220 by 465 feet

5. Jim Bridger Unit 3 Comparison with Huntington Unit 2

For purposes of this comparison, it is helpful to tabulate the salient characteristics at each plant that would affect their suitability to incorporate water saving technologies described herein.

Characteristic	Huntington Unit 2	Jim Bridger Unit 3	Impact at Jim Bridger
Terrain	Located in canyon	Hilly terrain	About the same at each location
Available Space	Limited	Relatively crowded	The site may not have sufficient space to support the installation of large fin fan coolers at Jim Bridger
Capacity, MW	450	528	Approximately 17-percent more space would be required to attain the same level of water usage reduction at JB than at Huntington.
Cooling Tower Cycles of Concentration	12	19	These values mean that PacifiCorp already has reduced the amount of blow down water it discharges.
Heat rate	10,030[10]	10,436[11]	A slightly higher heat rate indicates more heat rejection from the steam cycle. If this "budgeted heat rate" for Jim Bridger is valid, the various improvements suggested for Huntington would be slightly more effective at Bridger due to its higher heat rejection per kWH.

More data and time are required to provide an accurate assessment of the specific differences between Huntington Unit 2 and Jim Bridger Unit 3. Data and drawings that were supplied point to more similarities than differences between the two plants. On-site investigations as well as detailed studies are required to assess the applicability of water savings methodologies and technologies at each plant.

6. Operation and Maintenance Cost Estimates

a. Wet Dry Cooling Tower

Preventive maintenance on a wet-dry cooling tower would not be significantly different than the maintenance currently being carried out on the existing cooling tower, with the exception that the dry section would add incremental costs for cleaning, descaling and additional corrosion protection chemistry control. One difference would be that the wet-dry tower is inherently more complex than a conventional cooling tower and has additional piping, valves and structural members.

The wet-dry cooling tower would require the same attention to chemistry control, motor, pump and fan maintenance and permitting activities that are currently being provided. The addition of the dry section adds materials to the system that are not necessarily found in the current system. Their corrosion prevention could possibly require additional additives in the chemistry control program.

[10] 2013 Budgeted Heat Rate for Huntington Unit 2, see next note for source.
[11] 2013 Budgeted Heat Rate for Jim Bridger Unit 3. Budgeted heat rates provided in "***Heat Rate for 12 Months for PacifiCorp Power Plants 8-19-2013.xlsx***" plant data and forecasts.

An approximate annual cost of $3.2 million was developed by tabulating the various maintenance activities required, including but not limited to:

1. Continuous and periodic chemistry addition
2. Chemical monitoring and reporting activities
3. Water "trash" screen maintenance
4. Corrosion and structural inspections
5. Winter de-icing
6. Equipment lubrication
7. Air permit required reporting
8. Structural checks and adjustments
9. Basin cleaning
10. Circulating water pump maintenance
11. Spray nozzle replacement

Only about half of the estimated $3.2 million, between $960 thousand and $2.2 million would represent additional costs since PacifiCorp already operates a cooling tower at the site albeit approximately half the size of the proposed new tower.

b. Fin-Fan Coolers

This option would superimpose completely separate, dry heat exchangers next to the existing cooling tower. Therefore all of the maintenance requirements of the existing cooling tower would be combined with the maintenance of the 44 fin-fan coolers, motors and fans. These additional maintenance items would include, but not be limited to:

1. Motor and fan lubrication
2. Torque checks on structural members
3. Tube and fin periodic cleaning
4. Fin straightening after hail storms
5. Belt tension checking and adjustment
6. Flow adjustment to correct for cool and hot spots
7. Fan blade angle adjustment

It is estimated that the annual cost of maintenance for the entire fin-fan addition would be between $2.7 and $6.3 million per year in addition to the existing cooling tower maintenance already being undertaken.

Maintenance costs for the two options are different by approximately $3 million per year with the advantage going to the wet-dry cooling tower option. It should be noted that, as mentioned above the fin-fan heat exchanger option would add significant fan horsepower to the plant loads, thereby reducing plant capacity.

7. Conclusions and Recommendations

Overall the comparison of the two selected water reduction options is straightforward: The installation of a wet-dry cooling tower is significantly less expensive than the installation of fin-fan heat exchangers *and* annual maintenance costs are lower with a wet-dry system. Additionally, the wet-dry approach adds significantly less plant electrical load therefore annual production is not impacted as much as it would be by installing the fin-fan coolers.

The wet-dry option would cost an estimated $38.7 to $90.3 million versus $64.6 to $151 million for the comparable fin-fan approach. Additionally, annual maintenance for the wet dry system is estimated to cost between $960 thousand and $2.2 million versus $2.7 and $6.3 million for the fin-fan option. The estimated between $2.7 and $6.3 million annual maintenance for the fin-fan coolers would be *in addition* to existing cooling tower maintenance costs of approximately $1.6 million therefore it is significantly more expensive to maintain than the wet-dry cooling tower option.

The described options would reduce water usage by approximately 34 to 35 percent on an annual basis and if more water usage reduction were required, additional dry heat exchangers could be installed. This could take the form of additional wet-dry cooling tower cells or perhaps more of a hybrid system utilizing a wet-dry cooling tower with auxiliary fin-fan heat exchangers in concert with it.

Appendix 1
Performance Modeling

HEAT BALANCE MODELING

The heat balances described below are based on assumed data for the main turbine cycle, condenser, and cooling tower. The performance produced using this is assumed to be similar to that using the actual equipment.

General

The Huntington Unit 2 power plant is a nominal 450 net MW subcritical unit located near Huntington, Utah. It presently employs a wet mechanical draft cooling tower for cycle cooling. The purpose of this study is to simulate performance and water savings capabilities of two different cooling systems which employ dry cooling. The water usage and performance impacts are evaluated against those of the existing all wet mechanical draft cooling tower.

Main Power Cycle Description

The power cycle employs a steam turbine designed to produce approximately 450 MWe. The turbine is a GE two-flow turbine with 33.5-inch long last stage blades. This is all that is known about it at this writing.

The cycle has seven stages of feedwater heating and uses a turbine driven boiler feedwater pump. The boiler feed pump turbines exhaust into the main condenser. SWI's main heat balance modeling utilized Thermoflow's Thermoflex software (Tflex) to simulate plant performance. The basic heat balance was tuned to the GE steam turbine heat balance so the results would be consistent. For modeling purposes, the assumed condenser pressure from the GE heat balance was 2.0-inches of mercury, absolute (2" Hg. A).

Cooling Systems Studied

The existing cooling system as mentioned above is a wet mechanical draft cooling tower. It was used as the base case in our modeling with which the two dry cooling systems were compared. The systems described below with dry components are designed to save 35 to 40% of the annual makeup water relative to the all wet cooling tower.

The first of the dry systems employs a mechanical draft wet-dry system. This is where the dry surface and wet surface are integrated into a single cooling tower. As with the wet tower, this one is divided into several cells with one fan serving each cell. Cooling water enters the dry section first at the upper part of the tower and is cooled to a certain extent then it enters the wet portion below. This portion is much like a conventional wet cooling tower. Because of the dry section below it, the wet section does not have to do as much cooling as it would with the existing cooling tower because the water entering it has been precooled by the dry section. The dry section is more effective in cooler weather. The fans are located at the top of each cell. They bring air into the tower through both dry and wet sections simultaneously.

The second evaluated system also employs dry and wet sections. However in this case they are totally separate. The dry portion is composed of fin-fan coolers. These cool the incoming circulating water to a certain extent depending on ambient conditions. As with the dry sections of the wet-dry tower above, they are more effective in cooler weather. The outlet water from these enter a conventional all wet mechanical draft tower for the remainder of the required cooling.

<u>Ambient Conditions</u>

ASHRAE Weather Data for Price, Utah is used to obtain “bands” of data for use in calculations relative to the cooling system. This data is plotted as continuous curves of dry bulb temperature (DBT) and mean coincident wet bulb temperature (MCWB) versus percent of occurrence. These curves were then sliced into 4 bands of dry and wet bulb occurrence. Each band is 2,190 hours long or 25-percent of one year. The bands add up to a total of 8,760 hours which is the number of hours in one year.

Site altitude is assumed the same as that in ASHRAE which is 5,902 Ft ASL (above sea level).

The design point dry and wet bulb temperatures are assumed to be 87°F dry bulb (DB) and 57°F mean coincident wet bulb (MCWB). This and each band are tabulated below, including relative humidity (RH), another required input to Tflex. Also included is the same data with a 2°F recirculation allowance for the wet cooling tower portions, where applicable. These are designated as entering wet bulb temperatures (EWBT).

Band	Design	1	2	3	4	
DBT, °F	87	72	54.5	36.3	23.8	
MCWB, °F	57	52	42.5	31.6	22.8	
Recirc, °F	2		2	2	2	0
EWBT, °F	59	54	44.5	33.6	22.8	
RH, %	20.31	34	49	79	89	

These values are input to Tflex for solving groups of heat balances simultaneously. This is done by using the “Multiple Runs” feature.

<u>Condenser</u>

Since no condenser data is presently provided, an assumed condenser design was used. This same design (tube size, area, etc.) is the same for all calculations in this study. Of note here is the cleanliness factor. A typical value of 85% is used for all cases.

<u>Condenser Pressure Control</u>

In the modeling process, condenser pressures at each ambient condition are set by turning off cooling tower cells as necessary to prevent LP turbine choking and to maximize generation. For simulations of dry cooling, this also saves evaporation of circulating water in the respective wet sections. These pressures range from 2.28 In. Hg. A. at the design condition to 2.08 In. Hg. A. for the lowest temperature band. This is easily done within Tflex with the Multiple Runs feature where the number of operating cells can be one of the controlled variables.

<u>Auxiliary Power</u>

Auxiliary power was calculated based on calculated values generated by the Tflex model which are related to the respective cooling system type and are taken into account in annual power generation calculations.

Operating Conditions

In order to calculate the water savings and the power penalties for the dry cooling systems, operations factors must be assumed for each time period. For simplicity, this value has been assumed to be 85-percent for each ambient temperature band. Calculation of performances for each temperature band as well as for the design point, are done in Tflex with the Multiple Runs option. The results of these calculations are then incorporated into an Excel spreadsheet along with the hours of operation at each ambient temperature band. The yearly generation in MWHr/Yr and the total cooling system makeup water requirement in Acre-Ft/Yr are calculated therein. This is done for all three cooling system arrangements. The two systems with dry components are compared with the current all wet system.

The deficits in annual generation and the savings of makeup cooling water are then calculated and tabulated.

Results

For the above described calculations the generation deficits and makeup water savings for each cooling system relative to the current, all wet system are as tabulated below:

System	All Wet	Wet-dry	Wet w/Fin-Fans
Generation Deficit, MWHr/Yr	Base	26,145	30,190
Generation Deficit, %	Base	0.87	1.01
Makeup Water Savings, Acre-Ft/Yr	Base	1,895	1,819
Makeup Water Savings, %	Base	35.67	34.24

A comparison is also made of heat rates. This comparison is not within this particular scope of work, but heat rates were supplied by the customer. Heat rate at Huntington Unit 2 ranges from approximately 10,250 Btu/kWHr to approximately 10,800 Btu/kWHr with the existing wet cooling tower system. As a means of model calibration, the Tflex model calculates an average value of approximately 10,450 Btu/kWHr for Huntington Unit 2 in its current configuration, which is within the historical range for the plant.

Appendix 2
Water Usage Reduction Spreadsheets

Overall Water Saving Potential of Two Technologies at the Huntington Unit 2, Huntington, UT

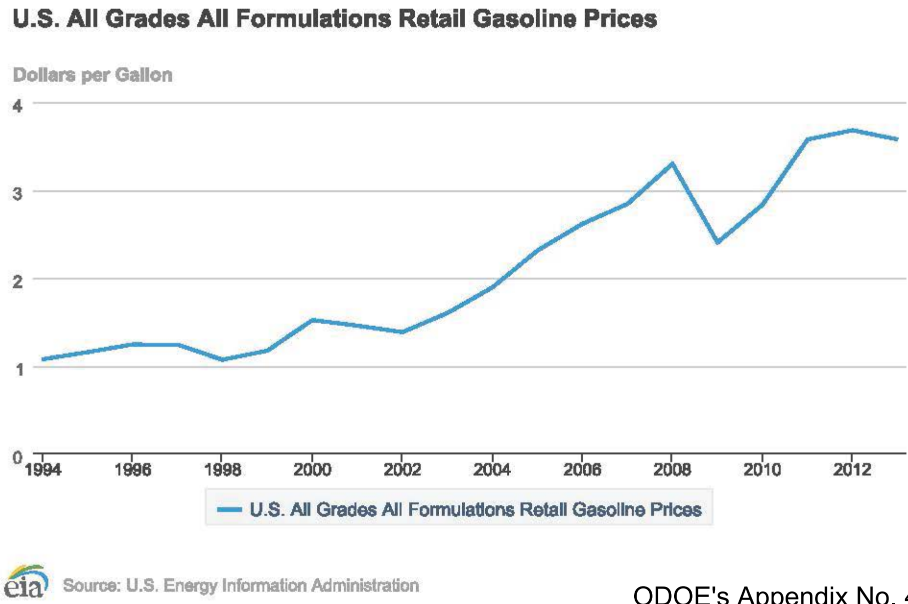
	Technology Option Description	Estimated Capital Cost (-40%) Upper End	Estimated Capital Cost (±40%) Mid Range	Estimated Capital Cost (+40%) Lower End	Potential Water Usage Reduction	Fixed Operating and Maintenance Costs	Variable Operating and Maintenance Costs	Total Estimated Operating and Maintenance Costs	Change in Net Heat Rate	Change in Net Capacity
Option 1	Wet-Dry Cooling Tower Installation[1]	$38.7 Million	$64.5 Million	$90.3 Million	35%	TBD[3]	TBD	$1.6 Million	-1.50%	-0.30%
Option 2	Fin Fan Cooler Installation[2]	$64.6 Million	$107.6 Million	$151 Million	34%	TBD	TBD	$4.5 Million	-1.30%	-1.50%

Notes:

1 The installation of a completely new, wet-dry cooling tower. This would not necessarily require the demolition of the existing cooling tower.

2 New fin-fan circulating water coolers would be installed which would be placed in parallel with the existing cooling tower for the unit.

3 TBD - To be Defined


U.S. All Grades All Formulations Retail Gasoline Prices
Dollars per Gallon
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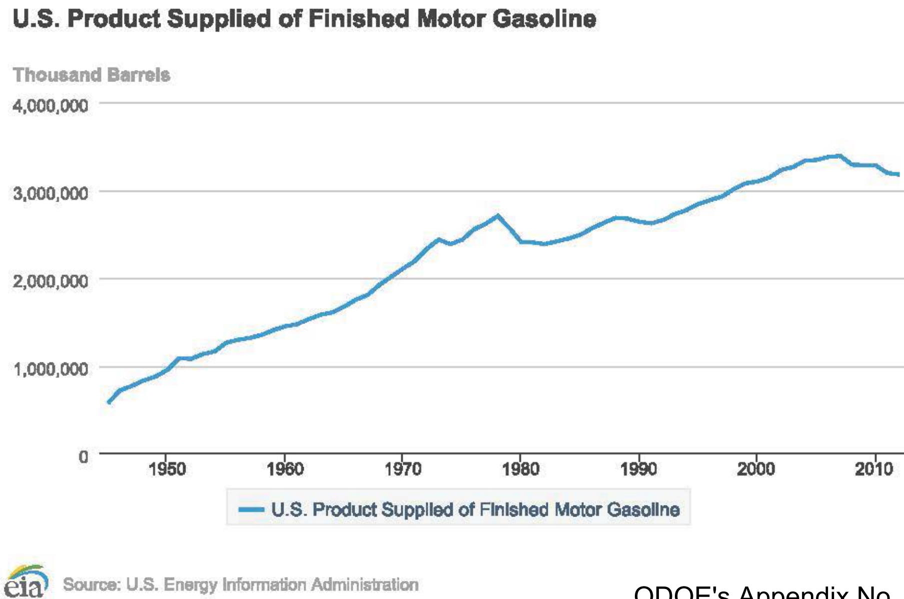
U.S. All Grades All Formulations Retail Gasoline Prices
Source: U.S. Energy Information Administration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Source: U.S. Energy Information Administration

EMB Development and Demonstration at Rocky Mountain Power

PacifiCorp is an electric utility serving customers in six western states. It has been working with a company called EMB Energy to demonstrate a breakthrough in energy storage for electric power systems. This storage system was pioneered at Lawrence Livermore National Laboratories by Dr. Richard Post who named it the *electromechanical battery* (EMB).

While there are various sizes and technologies being pursued by EMB Energy and its business partners, the energy storage system of greatest interest to PacifiCorp comprises (1) a high tech fiber composite flywheel, (2) a unique passive magnetic bearing system, and (3) an electrostatic motor generator. These three technologies will all operate in a vacuum with electrical feeds to power electronics that interact with the utility's ac power system. While specific design details are proprietary, it can be stated that the combination of these three technologies has the potential to greatly drive down the unit price of flywheel-based electrical energy storage.

Originally Rocky Mountain Power (RMP), a division of PacifiCorp, had a demonstration site picked that would connect a 25 MW / 25 MWh EMB plant to the utility at transmission voltage, envisioning an array of 100 flywheels, each sized at 250 kW / 250 kWh. However, recent changes in the development and planned manufacturing schedule of the flywheels dictated that the plant size be reduced by a factor of ten to 2.5 MW / 2.5 MWh. If the development by EMB Energy proves successful the present plan is that a demonstration site in Utah will be chosen. Currently RMP's level of support is to closely follow the EMB development.

With utilities around the world integrating significant amounts of intermittent non-dispatchable renewable energy into their power systems, the development of more cost effective electrical energy storage is increasing in importance. Once development of a cost effective EMB plant is clearly proven and demonstrated it is PacifiCorp's hope that this combination of technologies will become a valuable tool in serving its customers and meeting the needs of society.

CERTIFICATE OF SERVICE

I hereby certify that on January 10, 2014, I served the foregoing FINAL COMMENTS OF OREGON DEPARTMENT OF ENERGY upon all parties of record in this proceeding by delivering a copy by electronic mail only as all parties of the service list have waived paper service.

OPUC Dockets
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland OR 97205
dockets@oregoncub.org

Oregon Dockets
Pacificorp, dba Pacific Power
825 NE Multnomah St, Suite 2000
Portland OR 97232
oregondockets@pacificorp.com

Regulatory Dockets
Idaho Power Company
PO Box 70
Boise ID83707-0070
dockets@idahopower.com

RNP Dockets
Renewable Northwest Project
421 SW 6th Avenue, Suite 1125
Portland OR 97201
dockets@rnp.org

Kacia Brockman (C)
Oregon Department of Energy
625 Marion Street NE
Salem OR 97301-3737
kacia.brockman@state.or.us

Phil Carver (C)
Oregon Department of Energy
625 Marion Street NE
Salem OR 97301-3737
phil.carver@state.or.us

Ralph Cavanagh
Natural Resources Defense Council
111 Sutter Street, Floor 20
San Francisco CA 94104
rcavanagh@nrdc.org

Megan Walseth Decker (C)
Renewable Northwest Project
421 SW 6th Ave #1125
Portland OR 97204-1629
megan@rnp.org

Angus Duncan
Natural Resources Defense Council
2373 NW Johnson Street
Portland OR 97210
angusduncan@b-e-f.org

Renee M. France (C)
Oregon Department of Justice
Natural Resources Section
1162 Court Street NE
Salem OR 97301-4096
renee.m.france@doj.state.or.us

Wendy Gerlitz (C)
NW Energy Coalition
1205 SE Flavel
Portland OR 97202
wendy@nwenergy.org

Patrick G. Hager
Portland General Electric
121 SW Salmon Street 1WTC0702
Portland OR 97204
pge.opuc.filings@pgn.com;
patrick.hager@pgn.com

Fred Heutte (C)
NW Energy Coalition
PO Box 40308
Portland OR 97240-0308
fred@nwenergy.org

Robert Jenks (C)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland OR 97205
bob@oregoncub.org

Juliet Johnson (C)
Public Utility Commission of Oregon
PO Box 2148
Salem OR 97308-2148
juliet.johnson@state.or.us

Jason W. Jones (C)
PUC Staff--Department of Justice
Business Activities Section
1162 Court St NE
Salem OR 97301-4096
jason.w.jones@state.or.us

Brian Kuehne
Portland General Electric
121 SW Salmon Street 3WTC BR06
Portland OR 97204
brian.kuehne@pgn.com

G. Catriona McCracken (C)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland OR 97205
catriona@oregoncub.org

Derek Nelson (C)
Sierra Club Law Program
85 Second Street, 2nd Floor
San Francisco CA 94105
derek.nelson@sierraclub.org

Lisa D. Nordstrom (C)
Idaho Power Company
PO Box 70
Boise ID 83707-0070
lnordstrom@idahopower.com

Lisa F. Rackner (C)
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland OR 97205
dockets@mcd-law.com

Travis Ritchie (C)
Sierra Club Environmental Law Program
85 Second Street, 2nd Floor
San Francisco CA 94105
travis.ritchie@sierraclub.org

Irion A. Sanger (C)
Davison Van Cleve
333 SW Taylor - Suite 400
Portland OR 97204
ias@dvclaw.com

V. Denise Saunders
Portland General Electric
121 SW Salmon Street 1WTC1301
Portland OR 97204
denise.saunders@pgn.com

Donald W. Schoenbeck
Regulatory & Cogeneration Services Inc.,
900 Washington Street, Suite 780
Vancouver WA 98660-3455
dws@r-c-s-inc.com

Gloria D. Smith (C)
Sierra Club Law Program
85 Second Street
San Francisco CA 94105
gloria.smith@sierraclub.org

Mary Wiencke
Pacific Power
825 NE Multnomah Street, Suite 1800
Portland OR 97232-2149
mary.wiencke@pacificorp.com

(C)= Confidential

Renee M. France, OSB #004472
Senior Assistant Attorney General