BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 57

In the Matter of) PACIFICORP dba PACIFIC POWER) 2013 Integrated Resource Plan))	INITIAL COMMENTS OF THE NW ENERGY COALITION

The NW Energy Coalition (Coalition) appreciates the opportunity to provide comments regarding Pacific Power's (Company) 2013 Integrated Resource Plan. The Coalition participated in the pre-IRP workshop phase conducted by the Company for almost a full year before filing the IRP. We recognize the value of the extensive input the Company solicited through this process and believe that the result is a better and more robust IRP. Although the plan is improved, we offer the following comments to express areas of concern regarding certain aspects of the 2013 IRP and its associated Action Plan.

I. Introduction

Our overarching concern is that the Company continues year after year to focus on protecting business-as-usual – a reliance on outdated coal plants that are becoming increasingly expensive to operate coupled with a lack of appreciation for the reduced risk and cost offered by demand-side resources and newer resource options such as demand response, distributed generation and renewables. We fear that the Company's resulting decisions will lead to higher costs for all customers throughout Pacific Power's territory.

This IRP requests acknowledgement for upgrades at four coal units, underestimates the amount of Class 2 DSM available over the next five years, includes no significant acquisition of renewable resources and is overly reliant on front office transactions. The Public Utility Commission of Oregon (OPUC) should urge the Company to consider alternative action items that would serve Oregon customers energy needs while reducing risk associated with outdated supply side resource strategies in the face of emerging federal policy that favors clean energy and increasingly stringent regulation of GHG emissions.

II. Class 2 Demand Side Management

Accelerated DSM Case

The Company's 2013 IRP analysis indicates that case EG2- C15 is the least cost, least risk portfolio. This portfolio contained accelerated DSM assumptions, among other elements. This is in keeping with findings of the Northwest Power and Conservation Council and Puget Sound Energy regarding accelerated DSM being least cost and least risk. Despite this portfolio ranking least cost/least risk, it was not selected as the preferred portfolio based on the rationale that the accelerated DSM assumptions are not reliably achievable.

The IRP documentation gives no substantiation regarding the assumptions used, nor any detailed explanation of why specific assumptions used to obtain this accelerated DSM case were deemed unreasonable. Other differences between this portfolio and the final portfolio selected as the preferred portfolio (EG2-C07a) – including early selection of some Class 1 DSM and an inability to select CCCT resources -- remain completely unanalyzed in the IRP documentation.

The Company acknowledges that the rankings of case EG2-C15 illustrated the value of accelerated DSM. However, they fail to commit to higher DSM targets in the IRP Action Plan. Instead, the Company states that it incorporates some specific action plan items that attempt to achieve accelerated Class 2 DSM. The Company does not identify these specific action plan items, nor does it provide an indication of the amount of DSM acceleration expected from the action items. This approach is vague and lacks commitment to important Class 2 DSM resources.

The lack of firm DSM commitments that reflect the accelerated energy efficiency found to be least cost/least risk, in exchange for nebulous action items, further concerns us due to Pacific Power's mediocre track record for implementing DSM action items. Key items contained within the 2011 IRP Action Plan, that could have helped maintain consistent upward momentum on Class 2 DSM (and other efficiency improvements), appear not to have been implemented or were purposefully delayed by the Company. These items include:

1) Plans to acquire energy efficiency resources from the Company's Special Contracts customers in Utah and Idaho (2011 IRP Action Item 6).
2) The system-wide RFP (excluding Oregon) for specific direct install and other direct distribution programs targeting savings from residential and small commercial sectors (2011 IRP Action Item 6).
3) A study of cost-effective and reliable production efficiency opportunities at generating facilities (2011 IRP Action Item 4).

The Coalition recommends that the Commission urge Pacific Power, through specific Class 2 DSM targets in the IRP Action Plan, to continue rapid and robust progress on Class 2 DSM achievements that match those identified in the least cost/least risk portfolio Case EG2-C15. Specifically, the Company should commit to achieving the additional 1,113,250 MWh of Class 2 DSM (as selected in the accelerated DSM case) in the five-year action plan.

Underachieving Class 2 DSM in Non-Oregon States

In our review of Pacific Power's 2011 IRP, the Coalition expressed concerns that the Company underestimated the amount of achievable and cost effective Class 2 DSM for all states except Oregon. We remain concerned that this underestimation of available and cost effective Class 2 DSM in all states except Oregon continues in this 2013 IRP. This is especially concerning because the 2013 IRP relies heavily on front office transactions (FOT) and Class 2 DSM left unachieved will result in an increased reliance on FOT – and the market risks that are associated with those purchases. If Oregon ratepayers are funding an abundance of cost effective conservation and other states are not achieving their share, Oregon ratepayers are subsidizing ratepayers in all other states throughout Pacific Power territory. This effectively raises Oregon costs because cost effective energy efficiency opportunities elsewhere are forgone or delayed and that requires more expensive alternatives.

The Class 2 DSM achievable technical potential estimated by the Company's resource assessments declined considerably between 2011 and 2013 throughout the Company's service territory. There may be some valid reasons for that decline, including lower gas prices, changes in avoided costs, increase in implementation of codes and standards, etc. However, the achievable technical potential in Oregon declined only 13%, while the achievable technical potential in non-Oregon states showed a system-wide decrease of 44%[1].

The Coalition is concerned that methodologies used in the Cadmus study[2], including market ramp rate and measure ramp rate calculations, led to an underestimation of the achievable technical potential in all states (except Oregon).

The detailed results of case EG2-C15 appear to confirm the value of increasing Class 2 DSM in all non-Oregon states. In this case, the Company made more Class 2 DSM available to the model by accelerating ramp rates. At the same time, the Company increased the cost of these resources significantly ("increase in program administrative expenditures and customer incentives of 40% and 100% of incremental measure cost, respectively")[3].

Despite dramatic price increases, in case EG2-C15 the model chose significantly more DSM in the first five years of the plan period in all states except Oregon compared to the resources selected in the preferred portfolio[4]. In Oregon, the model chose the same amount (or sometimes slightly less) DSM in the first five years of the planning period as it did in the preferred portfolio. This indicates a model preference for more Class 2 DSM, even at a higher cost, in all states except Oregon. This result is puzzling, but appears to confirm that in Oregon we are currently planning to achieve all cost effective conservation – at higher prices, the model is not interested in accelerating our Class 2 DSM efforts because it is more expensive compared to other supply side resources.

Oregon ratepayers are paying for Class 2 DSM achievements that are keeping the costs down for all ratepayers throughout Pacific Power territory. The Company should be held accountable to acquire all cost effective conservation available in all states.

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[1] PacifiCorp Assessment of Long-Term, System Wide Potential, March 2013
[2] Ibid.
[3] See Pacific Power response to NWEC data request 2
[4] See Pacific Power response to OPUC data request 130

B) Modeling Improvements

Alterations made to the 2013 IRP approach to modeling DSM are a good step forward in improving the way DSM is considered along side supply-side resources. A more sophisticated approach to measure bundling and pricing proved successful. We appreciate that the modeling improvements came with some challenges, but hope this will not dissuade the Company from improving upon this approach in the next IRP cycle.

III. Coal Resources

The Company, since the initial filing of the 2011 IRP, has made great strides in improving its analysis of the costs and risks associated with upgrades to its coal fleet. These improvements notwithstanding, the Coalition maintains that the Company is still underestimating the cost and risk of continued reliance on coal generation. A failure to adequately address the full range of future regulations that will impact coal plants will saddle ratepayers with high environmental upgrade costs, stranded costs, or both.

The Company's coal analysis falls short in two main areas. First, the Company's base case modeling assumptions utilize a CO_2 price[5] that is too low and, second, the Company underestimates the likely requirements, and therefore costs, from known and unknown future environmental regulations that impose pollution control investments.

A) CO_2 Prices

The Company's base case CO_2 price curve used in the 2013 IPR has zero cost through 2022. This assumption is out of step with President Obama's Climate Action Plan and executive orders regarding CO_2 regulations. The EPA is expected to issue rules regulating greenhouse gas emissions from existing coal plants by June 1, 2014. Consequently, the timing and costs associated with greenhouse gas regulation are now expected to be much faster and higher than what the Company utilized in its base case. Therefore, the Coalition recommends that in reviewing the 2013 IRP, the Commission give more careful consideration to the high CO_2 scenarios and results in the IRP analysis.

[5] We use the term "CO_2 price" in the same manner that the Company applies this term in the IRP as a proxy for all potential future greenhouse gas regulation.

B) Cost of Future Environmental Regulations

Regarding pollution control cost assumptions, the Company models a base case and stringent case for regional haze requirements in order to reflect uncertainties in future regulatory decisions. Unfortunately, both the base and stringent cases used in the 2013 IRP analysis underestimate likely regulatory futures. The base case for regional haze requirements used by the Company in its coal plant analysis uses State Implementation Plan requirements that have already been rejected by the EPA, ensuring that base case cost assumptions are below likely costs. Further, the more stringent regional haze scenario used in the Company's analysis was proven inadequate in the face of the recent decision related to the implementation of the regional haze rule in Wyoming issued by the EPA on May 23, 2013. That decision indicates that the Company will be required to install more costly environmental upgrades on a number of coal facilities, exceeding the assumptions in the most stringent case analyzed in the 2013 IRP. Despite significant input from stakeholders warning that the stringent case was not stringent enough, the Company forged ahead with an analysis that we now know underestimates likely costs.

The Company is currently in the process of costly upgrades to its coal fleet. Many significant investments are planned over the next couple of years – four of which the Company seeks acknowledgement for in this 2013 IRP -- consequently, time is of the essence. From the perspective of consumer and environmental protection, it is important to ensure that the full range of costs and risks from likely regulation are understood in this 2013 IRP because the majority of PacifiCorp's coal plant investments will be made in the very near future.

We recommend that prior to Commission approval or acknowledgment of any coal plant upgrades contained in the 2013 IRP Action Plan, the Company be required perform a revised coal unit analysis that incorporates a broader range of current and future compliance scenarios that can be evaluated for economic and regulatory risk.

IV. Load Control and Demand Response

Load control and demand response are undervalued in the 2013 IRP. Despite Class 1 DSM Action Items from the 2011 IRP that called for at least 140 MW of incremental cost-effective Class 1 DSM by 2013, no incremental Class 1 DSM resources were added to the Company's system in 2011 or 2012 and none is selected in the preferred portfolio over the next 10 years. The Company also canceled the commercial curtailment product called for in another 2011 IRP action item. The Company explains in Chapter 9 of the 2013 IRP that the cancellation of these items was due to a revised load forecast.

Additionally, the 2013 IRP Volume 1 states that the Company completed an analysis of the feasibility and costs of west-side Class1 irrigation control, however, "it was not selected as an economic resource in the first ten years of the 2013 IRP preferred portfolio"[6]. Lack of information in the 2013 IRP and its appendices makes it difficult to understand what assumptions led to this surprising result. Closer Commission scrutiny of this decision is warranted given the expected value of summer peak load reduction to the Company's system given the estimated summer peak resource deficit of 824 MW beginning in 2013 and reaching 2308 MW by 2022[7].

Despite a 2011 Action Plan item to incorporate plug-in electric vehicles and smart grid technologies in the 2013 IRP, the Coalition can find no evidence that these things were actually included in the IRP analysis in any meaningful way. No discussion of these items or how they were included in the analysis is found in Volume 1 or Volume 2 of the IRP.

As technological development (distributed generation, smart phone apps that manage home energy use, etc.) makes it easier for customers to become an active part of the electric system, the Company should seek methods to use this technology to the benefit of the overall system. Demand response and other load control tools will play an increasingly important role in managing peak loads, integrating renewable resources and thus keeping costs down for customers.

The Coalition recommends close Commission scrutiny of the underlying model assumptions in the 2013 IRP that seem to have led to an undervaluing of Class 1 DSM. Additionally, we think the capacity oriented selections in case EG2-C15, and the potential contribution to this case's least risk/least cost ranking, should be analyzed more fully in the IRP. We also recommend that

[6] IRP, Volume 1, page 257
[7] IRP, Volume 1, page 79

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.

V. Renewable Resources

One notable aspect of the 2013 IRP is that the robust renewable energy effort made by the Company in recent years seems to be slipping backward. Roughly summarizing new capacity additions in Table ES-3 in Volume 1, for 2013-2022, front office transactions are 1076 MW (average per year), new combustion turbines 645 MW, new energy efficiency is 958 MW, and renewables only 138 MW (mostly distributed solar enabled by Utah state policy, and no new wind or geothermal). Additionally, the Company's decision to comply with Washington's RPS with unbundled REC's, rather than the new wind resources selected in the original preferred portfolio (case EG2-C07), is a short-sighted decision. Using unbundled RECs for Washington I-937 compliance is not supported by a full analysis in the IRP and, therefore, exposes the Company to unquantified, but likely substantial, risks.

The Company's plan to comply with Washington's I-937 with unbundled renewable energy credits (RECs) is not fully supported by a least-cost, least-risk analysis. The Company should have included unbundled RECs as an option for selection in System Optimizer, a modeling decision that would have more thoroughly tested the cost and risk. Instead, after all modeling was complete, the Company compared current REC prices, with no price future projections, with the cost of RPS resources selected by the model in the preferred portfolio. While the Company has shown that at current prices unbundled RECs offer a low cost compliance option, the Company has not measured the risk benefits of physical compliance. Physical compliance with I-937 will reduce fuel volatility risk, REC pricing risk, and Production Tax Credit availability risk relative to an unbundled compliance strategy. The omission of any consideration of a forward price curve for REC purchases is also concerning.

The Company's plan to physically comply with I-937 using unbundled RECs should remain unacknowledged by the Commission until such time as the Company performs a more complete analysis of the costs and risks involved in unbundled REC purchases for compliance.

Regarding the overall shortfall in renewable energy additions in the 2013 IRP, there are several contributing factors, but the Coalition believes that the primary ones are an overestimation of renewable prices, especially solar, and an underestimation of future gas prices and price volatility.

A) Solar Costs

The IRP starts with too high a current cost for solar PV and does not incorporate the likely decline in costs over both the short and long term. Aside from a small amount of solar DG enabled under state policies, there are no further acquisition targets or pilot programs included in the Action Plan, despite the fact that PacifiCorp territory includes some of the best solar resources in the nation. Because much of the Company's system is summer peaking, there is a substantial opportunity to develop solar at scale to assist with adequacy and reliability and reduce the need for expensive contingency and balancing resources.

The IRP anticipates only modest price reductions for solar PV throughout the 20-year planning period, not enough to make a substantial difference in the resource mix. Yet experience curve analysis over four decades and more recent trends suggest deep cost reductions will occur in the coming years. As a result, solar resource acquisition by 2022 and 2032 in the IRP is a fraction of the potential that actually exists. The Company's solar price projections need to be reevaluated.

The Company's analysis significantly overstates the current cost of solar PV at both local ("rooftop") and utility scale, by perhaps 10% and possibly more. The following comments focus on rooftop solar because of the greater amount of comparative data; we believe the current cost projections in the draft IRP for utility scale solar may also be high.

Table 6.8 (2013 IRP, Volume 1, pg. 126) sets the rooftop solar PV cost for Washington in mid-2012 at $6,835/kW-ac ($2,011 tax incentive, $131 administrative cost and $4,693 net capital cost). However, substantial evidence is available showing that actual installation costs are lower. Utah Clean Energy submitted additional data during the stakeholder process in September 2012 showing lower current solar PV costs, and there are numerous references elsewhere in published reports supporting the conclusion that the draft IRP costs are overstated.

Most recently, Lawrence Berkeley National Laboratory (LBNL) has published its authoritative 6th annual report on US solar PV small-scale and utility-scale costs[8], based on a range of data sources and thorough data review. Their report shows 2012 small system (< 10 kW) installation costs of $6,413/kW-ac (adjusting the reported value of $5,300/kW-dc by PacifiCorp's assumed dc-to-ac conversion rate of 1.21). In addition, the LBNL report notes that, for various reasons relating to market structure and incentives, California costs are higher than average ($5,700/kW-dc) and since the state includes about half of all installations, it skews the national results upward. The only other PacifiCorp state in the LBNL top-20 data, Oregon, has an average cost of $5,100/kW-dc ($6,171/kW-ac), which we consider a reasonable estimate for PacifiCorp territory – about 10% less than the 2013 IRP cost of $6,835.

Furthermore, costs continue to fall very quickly: "Partial data for the first six months of 2013 indicate that installed prices have continued to fall, with the median installed price of projects funded through the California Solar Initiative declining by an additional $0.5/W to $0.8/W (10-15%) depending on system size, relative to systems installed throughout all of 2012[9]."

Perhaps more important than accurate current costs is the projection of future solar PV costs. This is because solar PV is still relatively immature and subject to learning curve effects ("experience curve"). The Coalition recently submitted a paper to the Western Electricity Coordinating Council summarizing the field of experience curve research and its application over several decades to solar PV[10].

The essence of experience curve research on solar PV is that, at decadal scales and longer, there is a very robust learning rate of about 20% for modules and 15% for other costs for each

[8] Barbose, G.L., Darghouth, N, Weaver, S, Wiser, R.H, *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*, August 2013, Report LBNL-6350E, Lawrence Berkeley National Laboratory, http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf. The supporting data file is found at http://emp.lbl.gov/sites/all/files/lbnl-6350E-data.xls.

[9] LBNL report, page 1

[10] "Experience Curves and Solar PV," NW Energy Coalition, http://www.wecc.biz/committees/BOD/TEPPC/SPSG/MDTF/120906/Lists/Minutes/1/2012-09-03-nwec-experience-curves-and-solar-pv.pdf.

doubling in aggregate global market size. While doubling rates have varied over time, in recent years it has been once every three years or less[11]. This pace may not continue on an extended basis, but over the last decade or more the sustained rate for doubling periods for global aggregate solar PV capacity has certainly been less than 4 years.

Assuming a reasonable doubling rate for the solar PV market globally over the planning period from 2013 to 2032 produces very different results than solar cost projections used by the Company in the IRP. On September 28, 2012, The Cadmus Group prepared a memo[12] for the Company on solar PV costs and market potential. Cadmus proposed a nominal annual cost decrease of 4.6%, which on a present value basis is close to zero. Thus solar PV costs in 2022 and 2032 would be nearly the same as today, confounding all current price trends plus the four-decade long history of experience curve analysis for solar PV.

A very simplistic analysis shows how far off the mark this is likely to be. Assuming for simplicity sake a current rooftop solar PV price of $6,000/kW-ac, module prices of $1,000 ($1.00/W) and the remainder for rest of system, and learning rates of 20% for modules and 15% for rest of system costs, produces the following results:

	Module	Rest	Total
Learning Rate	20%	15%	
2012	$1000	$5000	$6000
2016	800	4250	5050
2020	640	3612	4252
2024	512	3071	3583
2028	409	2610	3020
2032	327	2219	2546

[11] Stephen Lacey, "2/3rds of Global Solar PV Has Been Installed in the Last 2.5 Years, and capacity will nearly double in the next 2.5 years," Green Tech Media, August 13 2013, http://www.greentechmedia.com/articles/read/chart-2-3rds-of-global-solar-pv-has-been-connected-in-the-last-2.5-years

[12] The Cadmus Group, "Revised Overview of PV Inputs, Data Sources, and Potential Study Results, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PAC_2013IRP_Memo_PVInputs_09282012.pdf.

For a number of reasons we believe this analysis is quite conservative: (1) the global aggregate capacity is likely to double more quickly than every 4 years on average over the next two decades; (2) balance of system costs, which are quite high in the US, are likely to come down faster; and (3) solar PV even in the cloudy Northwest will reach "grid parity" within the next decade, continuing accelerated market penetration and bringing down costs even as the technology matures.

For the reasons noted here, we believe the specifications in the PacifiCorp IRP modeling need a complete review for both local ("rooftop") and utility-scale solar PV. We recommend that the Commission request the Company convene appropriate workshops for the next IRP update or full IRP.

B) Natural Gas Price Levels and Volatility

The current IRP modeling framework does not capture the full diversity and risk hedging value of clean energy resources such as energy efficiency, demand response and renewables. Throughout the industry, there is a great deal of diversity among natural gas price forecasts and, historically, the price of natural gas is known to be highly volatile. The future of gas prices is likely to be determined by three major factors: geology, breakeven costs, and the changing structure of demand.

There is a sharp divide on how the shale gas era will transpire. In one camp are optimists who expect a shale "manufacturing model" to prevail, with prices staying relatively stable and low for the next two decades and more. A different "realist view" finds that well production decline rates from shale and other source rock plays are substantially steeper than production from conventional pools. Recent statistical analysis is providing some verification of that view[13].

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[13] "The abnormally high decline rates for shale gas have been recorded in producing wells from the very onset of field development. Recovery efficiencies calculated with these new decline EUR values for the Barnett and Fayetteville are 5.8% and 10%, respectively; this contrasts significantly with recovery efficiencies of 75-80% for conventional gas fields." Rafael Sandrea, "Evaluating production potential of mature US oil, gas shale plays," Oil & Gas Journal, December 3, 2012. Also see: *Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States*, U.S. Geological Survey Oil and Gas Assessment Team, Open-File Report 2012–1118.

There is growing evidence that since 2008, gas prices have been kept down by a condition of chronic oversupply because of the recession, the rush of production from new shale plays, demand destruction from previous high-price periods, and other factors. Although current prices hover below $4/mmBtu and most projections show costs rising only modestly over the next two decades, some analysis say that the breakeven price of gas today is $6 or above[14] and rapid well decline rates create a "shale treadmill" where new wells must be drilled at an ever-increasing rate, raising costs even further and putting upward pressure on market prices[15]. Demand factors for gas are also beginning to catch up to supply in four major areas: new power plants, industrial load, vehicles and export. However, these developments are still in the early stage and will take several years to mature.

The application of a carbon price affecting natural gas prices also is likely to be a matter of time. Though gas combustion has a lower CO_2 emission rate than coal, it is still substantial, and research showing higher methane escapement than previously understood in gas production, transportation and distribution is increasing that risk exposure.

The volatility of gas markets and inability to purchase or hedge effectively beyond the 5-year time horizon is likely to continue. Selecting new baseload gas units to replace coal one-to-one ties up capital and operating expenditures for two decades or longer, exposing the Company and its customers to further market and carbon price risk. Indeed, some utilities are beginning to invest in wind and other clean energy resources above any regulatory requirements in order to hedge against gas price volatility. In our view, relying less heavily on gas going forward is the prudent path, both because of continued volatility and the risk in long-term price trends.

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[14] Michele Michot Foss, *The Outlook for U.S. Gas Prices in 2020: Henry Hub at $3 or $10?*, Oxford Institute for Energy Studies, NG-58, November 2011, Fig. 14, p. 37.

[15] Arthur Berman, "U.S. Shale Gas: Magical Thinking & The Denial of Uncertainty," presentation at Nicholas School of the Environment, Duke University, January 9, 2012, http://www.nicholas.duke.edu/hydrofrackingworkshop2012/presentations/Presentation-Berman.pptx

This argues for planning that handles volatility and risk management more effectively, and for a resource portfolio that more completely hedges price risk, fully recognizes the environmental and climate impacts of gas, but also takes advantage of the flexibility and reliability of the resource.

While considering a range of natural gas prices in the IRP analysis provides some consideration for price risk, a fully dynamical modeling approach such as the Regional Portfolio Model (RPM) used by the Northwest Power and Conservation Council might assist in characterizing the uncertainty and risk aspects of the system, including the important drivers of natural gas price volatility and future carbon price.

We recommend that the Commission urge the Company to review and improve its methodology for including natural gas price uncertainty and risk in IRP modeling in the next IRP.

VI. Transmission

Energy Gateway represents one of the largest proposed transmission investments in North America. Some time ago, PacifiCorp estimated a total cost if all segments are built of at least $6 billion, and the ultimate price tag could be significantly greater. The 2013 IRP moves transmission into the spotlight in a major way. One of the most significant enhancements is the assessment of all 19 planning scenarios against four subsets of the Energy Gateway package, ranging from a few transmission projects to the entire group of active projects, as well as a no-build option. This adds great range to the results in the IRP. The Company is to be commended for its sophisticated transmission analysis.

The Coalition is concerned that, due to other assumptions and resulting conclusions in the 2013 IRP, the transmission analysis does not fully analyze transmission needs for a scenario in which existing coal plants are phased out more quickly in line with Clean Air Act mandates, including greenhouse gas emission reductions, and new energy efficiency and renewable energy as well as new gas resources are provided as a replacement mix.

Specific transmission questions remain unanswered due to the Company's overall emphasis on updating coal generating resources as opposed to pursuing alternative future resource strategies. Could earlier phase-out of coal plants in Wyoming free up available transmission capacity and defer or allow different routing of Energy Gateway segments to improve reliability and pick up more diverse renewable energy? What can be done in central and eastern Idaho to expand renewable generation, help Bonneville address its need to meet its southeast Idaho load obligations and Idaho Power address its ongoing load growth and clean energy development opportunities? Can PacifiCorp continue its effort with Bonneville and PGE to meet its system obligations and expand clean energy pathways in the core areas of the Northwest?

We recommend that the Commission encourage the Company to consider a broader range of future supply scenarios in its future transmission analysis.

One other specific issue regarding the Company's 2013 IRP transmission analysis is the System Operational and Reliability Benefits Tool (SBT), intended to identify the benefits of proposed transmission segments. We agree this is a promising tool because the system wide models typically fail to capture the effects of these projects in sufficient detail for stakeholder and regulatory assessment. We also agree that the development of this tool is in the preliminary stage and needs more refinement before the results can be relied upon.

In the IRP, the SBT is used to assess the Sigurd to Red Butte and Windstar-Populus (Segment D) projects. However, the Company has not clearly explained how the SBT results should be used to assess whether these and other projects should go forward. In addition, further work and stakeholder review is needed for the elements comprising the SBT.

Finally, one element of the initial SBT, Customer and Regulatory Benefits, does not have a sufficient step-by-step approach nor data and documentation to warrant its inclusion in this IRP. Customer and Regulatory Benefits is listed as "TBD" in the summary for Sigurd to Red Butte, which is being submitted for acknowledgment in the current IRP. In contrast, for Segment D, Windstar-Populus, Customer and Regulatory Benefits are listed as $249 million out of $1.165 billion total benefits. However, there is no detail provided regarding how this number was estimated. With projected costs at $934 million, this alone moves net benefits from slightly negative to $231 million net positive.

Much of the effect identified in Customer and Regulatory Benefits is the reduction of non-rate costs (loss of work time, food spoilage and many others) because outage events occur less often with new transmission reinforcing the grid. This is certainly a real effect. However, we raised concerns in the IRP workshops about making Customer and Regulatory Benefits additive to the other elements of the SBT. The effect can only be indirectly quantified through economic analysis and surveys, and there is a wide variation of the impacts of loss of load events based on the area affected, time of day, etc. The aggregate amount of Customer and Regulatory Benefits is far more sensitive to assumptions than the other elements of the SBT, and could bias results. Consequently, subject to further discussion in the SBT work group, we do not agree with including Customer and Regulatory Benefits with the other elements of the SBT at this time.

Thank you for the opportunity to submit comments regarding the Pacific Power's 2013 IRP. We hope our comments will encourage the Commission to provide closer scrutiny over an IRP strategy that favors risky coal plant upgrades over alternative resource selections that may prove to be least cost for Oregon ratepayers over the long-term.

Respectfully submitted,

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Senior Policy Associate
NW Energy Coalition

August 22, 2013

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **Initial Comments of NW Energy Coalition** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class Mail, postage prepaid and properly addressed, to those parties on the service list who have not waived paper service from OPUC Docket No. LC 57.

DATED this 22th day of August, 2013.

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Summary Report

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Summary Report

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