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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE FILING BY PACIFICORP DBA ROCKY MOUNTAIN POWER OF ITS 2009 ELECTRIC INTEGRATED RESOURCE PLAN (IRP).	))))))	**CASE NO. PAC-E-09-6** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its attorney of record, Scott Woodbury, Deputy Attorney General, and in response to the Notice of Filing and Notice of Comment Deadline issued on June 24, 2009, in Case No. PAC-E-09-6, submits the following comments.

BACKGROUND

On May 29, 2009, PacifiCorp dba Rocky Mountain Power (PacifiCorp; Company) filed its 2008 Electric Integrated Resource Plan (IRP)[1] with the Idaho Public Utilities Commission (Commission). PacifiCorp is a multi-jurisdictional utility and provides electric service to over 69,000 customers in eastern Idaho. The Company's filing is a biennial planning document that sets forth how the Company intends to meet the energy requirements of its customers over the

[1] Though submitted on May 29, 2009, PacifiCorp's IRP is entitled "2008 Integrated Resource Plan". Staff will refer to the document as the 2008 IRP, acknowledging that its submission comports with Commission directives aligning the timing of electric IRP filings beginning in 2009.

next 10 years. In Order No. 22299, the Commission directed PacifiCorp to file a biennial IRP that analyzes its customer base, load growth, supply-side resources, and demand-side management (DSM) resources. The Company's IRP was developed through a collaborative public process with involvement from regulatory staff, advocacy groups and other interested parties and, along with its 10-year business plan, provides a framework of future actions to ensure PacifiCorp continues to provide reliable service at a reasonable cost with manageable risk to its customers.

The key elements of the PacifiCorp 2008 IRP include a finding of resource need, focusing on the 10-year period 2009-2018, a preferred portfolio of supply-side, demand-side and transmission resources to meet this need, and the resultant action plan that identifies the steps the Company will take during the next 2 to 4 years toward implementation of the plan. The resources identified in the 2008 IRP preferred portfolio are considered proxy resources that guide procurement efforts, and do not constitute the actual resources that would be acquired as part of future procurement initiatives.

As has been the case recently, the 2008 IRP has undergone significant changes in order to portray an accurate representation of the planning environment and fulfill IRP obligations from various jurisdictions. Some of the changes from the 2007 IRP include:

- Alignment of its 10 year Business Plan with its IRP process
- Acquisition of the 520 megawatt (MW) Chehalis gas plant and 175 MW of additional wind resources added in 2008.
- New IRP guidelines issued by the Oregon Public Utility Commission on the treatment of carbon dioxide (CO^2) regulatory risk.
- Incorporation of the Energy Gateway Transmission Project in the portfolio analysis.
- State commission 2007 IRP acknowledgement orders calling for modeling methodology changes and the expansion of resource options to consider, including energy efficiency measures (Class 2 Demand-Side Management programs) and additional renewable energy technologies such as solar and geothermal.

An additional planning challenge for the Company has been to respond to and predict the demand response impacts of the economic recession and financial crisis. The Company states

that it is currently seeing a continuation of significant industrial and commercial sector demand reduction. This will translate, it states, into a reduction of resource need for the near-term. Volatile economic conditions and commodity prices are requiring the Company to continuously re-evaluate input assumptions and resource acquisition strategies. Significant price drops in fuels and forward wholesale power in late 2008 and early 2009 signal near-term opportunities to lower power supply costs through market purchases before the Company needs to commit to a large new thermal power plant. If construction markets continue to soften, as several experts predict, this will create additional cost-saving opportunities through lower plant prices.

The resource need accounts for load growth, sales obligations, existing resources, and a 12% planning reserve margin. Based on a November 2008 load forecast, PacifiCorp experiences a capacity deficit beginning in 2011, when the system will be short by 498 MW. The 2007 IRP forecasted deficits to occur in 2010 rather than 2011. The Company attributes the difference to lower demand, especially in the industrial sector, due to the economic downturn. The deficit increases to 1,936 MW in 2012 and 3,528 MW by 2018. The capacity deficit is driven by a coincident system peak load growth rate of 2.5% for 2009-2018, and expiration of major power contracts such as the Bonneville Power Administration peaking contract in August 2011. On an energy basis, the system begins to experience summer short positions by 2012.

To determine how best to address the capacity deficits, PacifiCorp developed 57 resource portfolios using a cadre of models that optimize resource choice according to both stochastic and deterministic variations of input assumptions and capacity planning criteria. PacifiCorp's state utility commissions require the Company, through its IRP standards and guidelines, to develop a portfolio that is least-cost after accounting for risk, uncertainty, and the long-run public interest.

STAFF ANALYSIS

Staff has reviewed PacifiCorp's 2008 IRP and commends the Company in its efforts to produce a sophisticated planning document amidst uncertain economic and political times. Staff had acknowledged in the previous IRP filing that integrated resource planning for PacifiCorp is becoming increasingly constrained by state and federal initiatives, and conventional 'least cost/least risk' portfolios are not necessarily the appropriate choice for the Company.

In meeting its stated IRP goals and requirements, PacifiCorp continues to expand its technical analysis of potential portfolios, applying an array of stochastic and deterministic

scenarios in order to identify what it believes is the preferred portfolio in which to base its action plan on. The Company developed 29 core cases and 19 initial sensitivity cases that were used to determine optimal resource portfolios. These portfolios were then assessed using Monte Carlo production cost simulations to test for sensitivity to key variable changes in order to pare down portfolios for a secondary analysis. The top-performing portfolios underwent deterministic risk assessment to ascertain the top performing portfolio, which will be discussed later.

Staff notes that amid the 2008 IRP planning process the nation faced, and is still facing, unprecedented economic turmoil. This has convoluted the process in numerous ways. For one, the Company is dealing with lower than expected load growth, especially in the commercial and industrial sector. In fact, there is evidence of load degradation among several large customers throughout its service territory. Also, the downturn has impacted the electric and natural gas markets to the extent that recent price escalation has diminished appreciably. Finally, there has been a recent softening of construction input markets, making capital cost estimates cumbersome as well.

Adding to the complexity of the planning is the evolving state and federal initiatives directed at curbing greenhouse gas emissions. The Company notes that it finds itself subject to increasing regulation among its states as compared to the 2007 IRP. Oregon, Washington, and Utah (California as well, though PacifiCorp is not required to file an IRP in that state) have standing or have recently passed greenhouse gas standards and renewable energy targets. On a federal level, the Waxman-Markey bill has received as much support on Capitol Hill as any other energy and climate bill in recent history. It is generally considered that some form of federal legislation affecting energy policy will occur under the current administration.

Given these state initiatives and looming federal mandates, the IRP planning process continues to be increasingly difficult to perform in terms of risk adjusted least cost planning in the near and long term. Additionally, state Commissions continue both implicitly and explicitly, to enact enhancements to the IRP planning guidelines in order to satisfy compliance requirements within their respective states.[2] Staff believes these additional requirements result in a more thorough level of scrutiny for portfolio selection while further convoluting the planning process.

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[2] See Appendix C of the 2008 IRP for PacifiCorp's view of state regulatory compliance. With the exception of California (where PacifiCorp is exempt from filing an IRP due to its low market penetration), all jurisdictions have added Company-specific requirements to the IRP, specifically in recent years.

Staff is disappointed that, to this point, there have been no intervening parties or public comments filed in this proceeding. This is the first such occurrence since the PacifiCorp's 2001 IRP filing. Following the 2001 filing, and the western energy crisis, the Commission had six intervening parties for the Company's 2003 IRP. Staff believes that given the long economic downturn currently occurring, combined with the large capital investments the Company is undertaking, public involvement is critical for producing a robust action plan for the near and long term.

Nevertheless, Staff respectfully submits the following comments in regard to PacifiCorp's 2008 IRP. Staff does not intend for these comments to be all-inclusive of the document, but rather will focus on a number of issues it deems important in determining the Company's action plan. On a summary level, Staff finds that PacifiCorp has done its due diligence according to prior Commission findings in developing a preferred portfolio and subsequent action plan. That said, Staff believes that the preferred portfolio was derived in a more 'deterministic' manner than in the past, and questions the methodology that led to the final result.

Resource Options

PacifiCorp continues to make strides in model flexibility toward resource selection. A substantial number of supply side resources were initially screened prior to inclusion in the System Optimizer run. Staff commends the efforts of the Company for its diligence in reasonably portraying capital and O&M costs, plant characteristics, and associated emissions, among other resource attributes. The Company continues to refine modeling of non-traditional supply-side resources, such as distributed generation, energy storage and geothermal by taking into consideration siting attributes like transmission savings and local investment credits.

Staff believes that the Company has put forth an exceptional effort in modeling demand-side resources in its IRP. The Company's current DSM programs are included in the model, along with additional opportunities developed through a DSM potential study, on a supply curve basis to allow the optimization models to select programs and quantities on a least-cost basis

alongside of supply-side resources. Class 1 and Class 3 DSM programs[3] were modeled as discrete supply curves for each individual program (four Class 1 Programs were included, and ten Class 3 programs were modeled). Accounting for the various jurisdictions, 24 Class 1 DSM supply curves and 50 Class 3 DSM supply curves were included for selection.

One of the main deficiencies in prior IRPs is the manual selection of so-called Class 2 DSM programs[4] preceding actual portfolio analysis. In the past, Class 2 DSM was included as a load decrement, and the system optimizing model did not have an opportunity to select additional levels of this particular resource. For this IRP, PacifiCorp has utilized the supply curve methodology for Class 2 DSM. The Company offers many such programs throughout its service territory, and including them individually would result in 12,500 distinct supply curves. *See* 2008 IRP, p. 127. To reduce this to a more manageable number, the Company bundled resources with comparable attributes and costs for each of its jurisdictions. Each bundle resulted in a series of supply curves available for resource selection.

Staff believes that the Company continues to improve on the modeling of demand side resources, and commends its efforts for including Class 2 DSM options in resource selection. Staff further notes that the Company has taken steps toward putting supply-side and demand-side resources on equal footing by accounting for the lack of transmission necessary for demand-side resources and distributed generation located within load centers.

For the 2008 IRP, the Company applies a discount factor of 7.4% to calculate the present value of future resources. This rate represents the after-tax weighted average cost of capital (WACC) and was chosen to comply with the Public Utility Commission of Oregon's guidelines from 2007. Using a set discount rate facilitates comparison between portfolios, but Staff believes that this may bias resource selection and timing within portfolios. Basic mathematics demonstrates that capital intensive resources would best be deferred to the end of the planning horizon simply because it is 'cheaper' than in a less heavily discounted period earlier in the horizon. Resources with low or no capital costs (such as market purchases) would tend to be added early in the planning period. Staff recommends that the Company conduct sensitivity analyses on the choice of discount rates on resource timing and selection. A standard inflation or

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[3] PacifiCorp classifies Class 1 programs as fully dispatchable, such as the Idaho Irrigation Load Control Program. Class 3 programs represent 'buydown' programs such as critical peak pricing and commercial/industrial demand buyback.

[4] Class 2 DSM programs are defined as non-dispatchable programs, namely energy efficiency measures such as See Ya Later Refrigerator and CFL giveaways that have lifetime load reduction impacts.

Treasury bond rate may serve as a potential lower bound, and the after-tax WACC may serve well as an upper bound.

Wind Integration

For the past several years, wind resources have factored heavily into the integrated resource and business planning environments for PacifiCorp. The 2008 IRP is no different, as the Company continues to improve upon its methods for representing diverse wind resources. The Company includes several sites and sizes for wind projects that can be selected by the models. Staff is satisfied that the Company, given its extensive knowledge of wind projects, has adequately portrayed its potential wind generation.

Staff notes that the Company included a wind integration cost of $11.75/MWh in its resource assumptions. The Company stated that it had not completed its own wind integration study for this IRP, and based its value on a study conducted by Portland General Electric. *See* 2008 IRP, p. 162. Staff agrees that integrating wind into its system does impose a cost, but does not necessarily agree with the value chosen by the Company. Given its geographic and resource diversity, PacifiCorp is in a comparatively good position to add wind resources at a lower integration cost than most Northwest utilities. Staff would put the chosen value as on the high side compared to studies performed by utilities such as BC Hydro and entities like Bonneville Power Administration.

The $11.75/MWh integration cost is more than double what was used in the 2007 IRP.[5] Furthermore, the Company argued before the Commission that its cost of wind integration hovers around $5.00. *See* Case No. PAC-E-07-07. Staff believes that there is a range of wind integration costs that vary by utility and percentage of wind on a utility's system. Prior to its next IRP filing, Staff requests that the Company explain and justify why its integration costs have more than doubled.[6] Staff further recommends that the Company perform stochastic modeling to ascertain a value as part of its next IRP.[7]

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[5] PacifiCorp calculated a cost of $5.10/Mwh for a penetration of 200MW of wind.

[6] Staff notes that the Company included a Wind Integration Cost Update as Appendix F of its 2008 IRP. Staff does not believe the information sufficiently supports the Company's use of $11.75/MWh, given the immense disparity from its previous findings less than two years ago.

[7] Staff differs to the thoughtful comments of the Utah Division of Public Utilities on discussion of whether there were statistical errors in modeling wind integration. Staff has reviewed and generally concurs with the Division's findings, but would rather address the issue in the context of a wind integration study review. *See* Utah Public Service Commission; Docket No. 09-2035-01.

Portfolio Modeling

PacifiCorp relies on a number of models to produce its preferred portfolio. Many of the models, such as MIDAS and PROSYM, are used to develop resource and input assumptions that are ultimately used by the System Optimizer and Planning and Risk (PaR) models for portfolio modeling and selection. These models, by in large, are proprietary and are not subject to review.[8] The Company provides its overview of the System Optimizer and PaR models to the planning participants in the form of a PowerPoint presentation. While Staff appreciates the Company's efforts, Staff nonetheless believes that, at a minimum, hands-on sessions with the two main models would be a beneficial addition to the planning review process.

For the 2008 IRP, PacifiCorp has incorporated current state renewable portfolio standards (RPS) as a constraint in portfolio selection. RPS commitments were modeled on a system basis, presumably due to technical limitations. An advantage to this process is the ability to 'bank' surplus credits for sales or meeting of out-year targets. The Company notes that a key assumption to this representation is that through the Multi-State Protocol (MSP), trading rules would be adopted by its multiple jurisdictions. *See* 2008 IRP, p. 161. Each portfolio is then re-run against an expected and high RPS requirement to determine what eligible resources would be added to achieve compliance.

Staff concurs that RPS requirements should be considered as a constraint placed upon the model, and at this time believes that the Company has included its best effort in doing so. However, Staff does not believe that PacifiCorp has adequately quantified the costs associated with meeting an RPS. Doing so would necessitate setting a base portfolio with no RPS constraint rather than current requirements, and comparing the costs of the resulting portfolios. Staff believes comparing portfolios with and without RPS constraints may facilitate discussions regarding cost allocation and trading rules for Renewable Energy Credits.

PacifiCorp created its 29 core and initial 19 sensitivity cases[9] under the pretense that the Company would complete an expansion of its Lake Side CCCT facility. The Company has subsequently decided to defer construction on the project. Staff is aware that the decision was

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[8] The Company has indicated to the Utah Commission that model review would require confidentiality agreements with the vendors, which Staff believes is burdensome enough to basically preclude thorough investigation of the models within the confines of the comment period, and a high level of coordination during the planning period.

[9] Two of the sensitivity cases were based on the Company's 2008 Business Plan. These portfolios contained fixed resources, business planning assumptions that differ, somewhat slightly, from the IRP assumptions, and October 2008 price forecasts.

made in February of this year, a period between the finalization of the planning document and its submission and commends the Company for providing additional portfolio analysis of this decision. However, the initial analysis has to be viewed with some skepticism without knowing the level of influence the inclusion of Lake Side II had on preliminary portfolio selection. PacifiCorp chose the eight top scoring portfolios from the previous modeling runs and conducted a secondary portfolio selection process with a handful of additional assumption changes.[10] Again, Staff is uncertain how the selected portfolios would have fared in initial modeling had Lake Side II not been included.

For both the initial and secondary portfolio screenings, eight metrics were used to score candidates for performance. The Company applied a weighting scheme to the metrics representing its view of relative importance. The metrics chosen, risk adjusted present value of revenue requirement and CO^2 cost exposure to name two, are generally satisfactory measures for the Staff. Staff does take issue with the weighting schemes. While the choice of metrics was clearly explained, the weighting scheme was devoid of any rationale. Staff is concerned that the weights were chosen arbitrarily, and may ultimately impact the selection of a portfolio over another equal or exemplary option. Staff requests that the Company discuss both during the planning process and within its final document, the development of the weighting scheme used.

Portfolio Selection

As noted earlier, PacifiCorp selected a handful of portfolios for secondary analysis with updated assumptions for final selection. The resultant preferred portfolio consists of a wide array of supply-side resources, including substantial amounts of renewables, resource upgrades, DSM, non-traditional resources (such as distributed standby generation), and market purchases. The Company has developed a plan that acknowledges the benefits of a diversified resource mix while adhering to imposed and impending environmental regulations. Unlike the 2007 IRP, no additional transmission capacity was included in the selected portfolio, namely due to the fixed transmission resources (Gateway project) included in the System Optimizer model. Also, Staff finds it noteworthy that coal-fired generation did not appear in the chosen portfolio. The preferred portfolio (labeled 5 in the IRP) is summarized below.

[10] Beyond the removal of the Lake Side II CCCT, PacifiCorp made updates to its topology and market depths used in modeling.

PacifiCorp 2008 Preferred Portfolio

	Resource	Capacity, MW 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Cumulative Total
East												
	CCCT F 2x1, Utah North	-	-	-	-	-	570	-	-	-	-	570
	IC Aero SCCT	-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement	-	-	-	200	-	-	-	-	-	-	200
	Coal Plant Turbine Upgrades	3	44	33	25	2	14	-	8	-	-	128
	Geothermal	-	-	-	-	35	-	-	-	-	-	35
	Wind	99	249	-	100	100	100	150	100	100	50	1,048
	Combined Heat & Power	2	2	2	3	3	3	4	4	4	4	30
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	38
	DSM, Class 1, Utah Cool Keeper Load Control	25	50	40	30	10	10	10	10	10	10	205
	DSM, Class 1, Other	*	*	*	*	*	*	*	*	*	*	Up to 90
	DSM Class 2	42	51	49	52	55	55	56	56	58	59	532
	Front Office Transactions	75	50	150	394	493	200	202	228	717	800	
West												
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	42
	Swift Hydro Upgrades [2]	-	-	-	25	25	25	-	-	-	-	75
	Wind	45	20	200	-	-	-	-	-	-	-	265
	CHP	1	1	1	1	2	2	2	2	2	2	16
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	12
	DSM, Class 1	*	*	*	*	*	*	*	*	*	*	Up to 30
	DSM, Class 2	35	36	39	39	38	39	39	39	39	29	372
	Front Office Transactions	-	-	59	839	839	739	739	689	289	582	

[1] The 99 MW amount in 2009 is the High Plains project; the 249 MW in 2010 includes the 99 MW Three Buttes wind PPA.

[2] The Swift 1 hydro updates are shown in the years that they enter into commercial service.

* Up to 120 MW of additional cost-effective Class 1 DSM programs (100 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2018. Firm market purchases (3rd quarter products) would be reduced by roughly comparable amounts.

Staff believes the selected portfolio satisfactorily meets the Company's forecasted load requirements at the 12% planning reserve margin[11], but questions the methodology that led to the selection of the portfolio. As Staff noted, a major planned resource was removed from initial portfolio screening, which leads to questioning of whether the portfolio (or any of the eight selected) would have made the initial cut.

Another anomaly in the modeling is that portfolio 5 had been manually adjusted to include either a 570 MW wet-cooled CCCT or 536 MW dry-cooled CCCT with an online date of 2014 (giving a total of 10 finalist portfolios). Other than stating that this reflects the Company's CCCT deferral strategy (p. 235), there is no other rationale used to support this "fixing" of resources. Staff is further confused as to why that particular portfolio was chosen for resource fixing, and not any or all of the others.

The Company further adjusted the preferred portfolio by manually distributing the selected wind resources throughout the planning period in a manner differing from the system optimizer runs. The preferred portfolio selected large additions of wind in certain years and none

[11] In fact, due to the inclusion of distributed standby generation, the given planning reserve margins may be slightly understated due to the nature of the resource.

in others. PacifiCorp revised the wind acquisition schedule to reflect a smoother and more suitable schedule for additional wind. The Company justifies doing so by stating that the "pattern, while optimal from the model's perspective, is not desirable from a business planning perspective." *See* 2008 IRP, p. 240. Staff finds merit in the Company's assertion, though this manual adjustment further evidences the deterministic aspect of the preferred portfolio.

Ultimately, the modeling exercise did not produce a portfolio that truly outperformed all others. Depending on the metrics and weighting scheme used, as few as three portfolios and as many as ten could have been selected by the Company. Staff is not endorsing one portfolio over another, rather pointing to inadequacies in the selection process.

The following table reflects the differences between the 2008 preferred portfolio and the preferred portfolio from the 2007 IRP update filed June 11, 2008. The large reduction in gas-fired resources in 2012 can be attributed to the acquisition of the Chehalis facility. The purchase defers the expansion of gas-fired generation to 2014, representing the manually fixed wet-cooled CCCT inserted by the Company into the ultimate preferred portfolio. For the years inclusive of both studies, Staff finds it noteworthy that reliance on market purchases is significantly lower under the 2008 IRP, which may be the result of pessimistic near term load forecasts as much as resource selection. Staff assumes that, in practice, the Company will undertake purchase opportunities as it sees fit to take advantage of the recently depressed wholesale electric market.

Difference In 2008 IRP Selected Resources and 2007 IRP Update Selected Resources (MW)

		Capacity, MW											Total
	Resource	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2008-2017
East	Gas Combined Cycle (2x1)		-	-	-	(1,096)	-	570	-	-	-	-	(526)
	IC Aero SCCT		-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement		-	-	-	201	-	-	-	-	-	-	201
	Coal Plant Turbine Upgrades		(18)	7	(5)	(12)	2	14	-	8	-	-	(4)
	Geothermal, Blundell 3		-	(35)	-	-	35	-	-	-	-	-	-
	Wind	36 [2]	(201)	149	(100)	(100)	100	(100)	150	100	100	50	134
	Distributed Generation		6	(13)	6	6	6	6	8	8	8	8	42
	Firm Market Purchases		75	50	150	279	(140)	(546)	(598)	(572)	(66)	800	NA
West	Chehalis CCCT	509 [1]	-	-	-	-	-	-	-	-	-	-	509
	Coal Plant Turbine Upgrades		-	(8)	(9)	(5)	(5)	-	-	-	-	-	(28)
	Swift Hydro Upgrades*		-	-	-	-	-	-	-	-	-	-	-
	Wind	139 [2]	45	20	-	-	(100)	-	-	-	-	-	104
	Distributed Generation		2	2	2	2	3	3	3	3	3	3	25
	Firm Market Purchases	(400)	(400)	(657)	(677)	(311)	30	(55)	(100)	(333)	(609)	582	NA
DSM [4]	Energy Efficiency (Class 2 DSM)	(67)	2	2	(2)	(3)	1	2	3	2	5	87	(55)

[1] Acquisition of the Chehalis 509 MW combined-cycle plant in Washington.

[2] For 2008, actual wind additions totaled 545 MW, compared to the planned amount of 370 MW in the 2007 IRP Update

[3] Expansions of the existing Utah Cool Keeper program and dispatchable irrigation programs are treated as existing resources. Relative to the 2007 IRP Update quantities, the incremental DSM planned expansions reach 525 MW by 2018.

[4] For the 2007 IRP Update, Class 2 DSM was treated as a decrease to load rather than as a resource included in the preferred portfolio.

Relationship to 2008 Business Plan

The 2008 IRP reflects an evolution in PacifiCorp's corporate resource planning approach. The Company has embarked on a strategy to more closely align IRP development activities and the annual 10-year business planning process. The purpose of the alignment is to adopt consistent planning assumptions, to ensure that business planning is informed by the IRP portfolio analysis and that the IRP accounts for near-term resource affordability, and to improve resource planning transparency for public stakeholders.

The Company notes that to an extent the alignment process was unsuccessful. *See* 2008 IRP, p. 20-21. Two specific objectives were not met: 1) the Company intended to conduct alternative portfolio development for the Business Plan utilizing different input assumptions and production cost simulations to compare portfolio stochastic costs and risks; and 2) public reporting goals on the progress of the Business Plan were not provided. Staff understands that due to input assumptions frequently changing and model enhancements, the Company simply ran out of time and could not perform such analysis and provide input prior to the MEHC board of directors approving the 2008 Business Plan.[12] Staff does not believe that the Company

[12] The Business Plan was approved in December 2008, prior to the final portfolio modeling and selection for the 2008 IRP.

purposely failed in coordinating the two planning documents, though Staff does expect that the coordination of the two will be improved by the 2011 filing.

2008 IRP Action Plan

PacifiCorp's 2008 Action Plan is included in Staff's comments as Attachment A. The Action Plan details the steps that the Company intends to take in order to acquire the identified resources and further improve the IRP process. While not endorsing the selected portfolio, Staff nonetheless believes the identified course of action is reasonable given the analysis and conclusions of the Company.

Staff further notes that new to this IRP, PacifiCorp has included an additional action plan devoted solely to transmission expansion. Staff commends the Company for providing additional discussion on its transmission planning, which describes eight segments of the proposed Gateway Transmission Project, including sizing and rough in-service dates for the lines.

Acknowledgement

In Idaho, as in most states, the Commission "acknowledges" or "accepts for filing" rather than "approves" a utility's IRP. Other states where PacifiCorp serves have similar IRP requirements and provisions for acknowledgement: however, "acknowledgement" may be viewed differently in some states than in others. Staff believes it is helpful to explain what it presumes is meant by acknowledgement in Idaho. The following policy on integrated resource planning, adopted by the Commission in Order No. 25260, Case No. GNR-E-93-03 is provided as a way of explanation:

> POLICIES ADDRESSING INTEGRATED RESOURCE PLANNING. Each electric utility regulated by the Idaho Public Utilities Commission with retail sales exceeding 500,000 kilowatt hours in a calendar year shall employ integrated resource planning. Each electric utility's integrated resource plan must be updated on a regular basis (no later than biennially), must provide an opportunity for public participation and comment, and must be implemented. This plan constitutes the base line against which the utility's performance will ordinarily be

measured. The requirement for implementation of a plan does not mean that the plan must be followed without deviation. The requirement of implementation of a plan means that an electric utility, having made an integrated resource plan to provide adequate and reliable service to its electric customers at the lowest system cost, may and should deviate from that plan when presented with responsible, reliable opportunities to further lower its planned system cost not anticipated or identified in new existing or earlier plans and not undermining the utility's reliability. In order to encourage prudent planning and prudent deviation from past planning when presented with opportunities for improving upon a plan, an electric utility's plan must be on file with the Commission and available for public inspection, but the filing of the plan does not constitute approval or disapproval of the plan having the force and effect of law, and the deviation from the plan would not constitute violation of the Commission's orders or rules. The prudence of a utility's plan and the utility's prudence in following or not following a plan are matters that may be considered in a general rate proceeding or other proceeding in which those issues have been noticed.

Furthermore, the Commission explicitly stated in Order No. 22299 its role in the IRP process: "...the Resource Management Report [now the IRP] is not designed to turn the IPUC into a planning agency nor shall the Report constitute pre-approval of a utility's proposed resource acquisitions." It is through these orders that Staff constitutes its view of acknowledgement.

The 2008 IRP represents PacifiCorp's continued effort to plan according to what is known at this point in time. Given the significant differences between the 2007 IRP, 2007 IRP update and the 2008 IRP, along with events noted in the 2008 IRP which have transpired between the document preparation and submission, Staff recognizes that the IRP process is a fluid one, and commends the Company for keeping the Commission apprised of the dynamic planning environment. While not convinced that the preferred portfolio represents the 'lowest system cost' portfolio when adjusted for risk, Staff nevertheless believes the Company did its due diligence in arriving at its conclusion. Staff reiterates its position from the 2007 IRP comments that resource procurement is relying less on cost/risk metrics, and more on political

constraints. Staff believes that PacifiCorp and the IRP participants should reevaluate the IRP process to identify the cost of jurisdictional mandates.

RECOMMENDATION

Staff believes that the Company has adequately met the Commission's requirements in regard to the 2008 IRP. While not endorsing the proposed action plan, Staff believes that PacifiCorp has performed extensive analyses, given equivalent consideration of supply- and demand-side resources, provided acceptable opportunities for public input, and that the end result is representative of the Commission's directives toward integrated resource planning. Staff therefore recommends that the Commission acknowledge the Company's 2008 IRP.

Respectfully submitted this 31st day of July 2009.

Scott Woodbury
Deputy Attorney General

Technical Staff: Bryan Lanspery

i:umisc:comments/pace09.6swbl comments

Table 9.2 – 2008 IRP Action Plan

Action items anticipated to extend beyond the next two years, or occur after the next two years, are indicated in italics

Action Item	Category	Timing	Action(s)
1	**Renewables**	**2009 - 2018**	Acquire an incremental 1,400 MW of renewables by 2018, in addition to the already planned 75 MW of major hydroelectric upgrades in 2012-2014; PacifiCorp's projected renewable resource inventory by 2018 exceeds 2,540 MW with these resource additions • Successfully add 144 MW of wind resources in 2009 that are currently in the project pipeline, including PacifiCorp's 99 MW High Plains facility in Wyoming, and 45 MW of power purchase agreement capacity • Successfully add 269 MW of wind resources in 2010 that are currently in the project pipeline, including 119 MW of power purchase agreement capacity already contracted • Procure up to an additional 500 MW of cost-effective renewable resources for commercial operation, subject to transmission availability, starting in the 2009 to 2011 time frame under the currently active renewable resource RFP (2008R-1) and the next renewable resource RFP (2009R) expected to be issued in the second quarter of 2009 – The Company is expected to submit company resources (self build or ownership transfers) in the 2009R RFP • *Procure up to an additional 500 MW of cost-effective resources for commercial operation, subject to transmission availability, starting in the 2012 to 2018 time frame via RFPs or other opportunities* – *Procure at least 35 MW of viable and cost-effective geothermal or other base-load renewables* • *Monitor solar and emerging technologies, government financial incentives, and procure solar or other cost-effective renewable resources during the 10-year investment horizon* • *Continue to evaluate the prospects and impacts of Renewable Portfolio Standard rules at the state and federal levels, and adjust the renewable acquisition timeline accordingly*
2	**Firm Market Purchases**	**2009 - 2013**	Implement a bridging strategy to support acquisition deferral of long-term intermediate/base-load resource(s) in the east control area until no sooner than the beginning of summer 2014 • Acquire the following resources: – Up to 1,400 MW of economic front office transactions on an annual basis as needed through 2013, taking advantage of favorable market conditions – At least 200 MW of long-term power purchases – Cost-effective interruptible customer load contract opportunities (focus on opportunities in Utah) • Resources will be procured through multiple means: (1) reactivation of the suspended 2008 All-Source

Action Item	Category	Timing	Action(s)
			RFP in late 2009, which seeks third quarter summer products and customer physical curtailment contracts among other resource types, (2) periodic mini-RFPs that seek resources less than five years in term, and (3) bilateral negotiations • Closely monitor the near-term need for front office transactions and reduce acquisitions as appropriate if load forecasts indicate recessionary impacts greater than assumed for the February 2009 load forecast • *Acquire incremental transmission through Transmission Service Requests to support resource acquisition*
3	**Peaking / Intermediate / Base-load Supply-side Resources**	**2012 - 2016**	Procure long-term firm capacity and energy resources for commercial service in the 2012-2016 time frame • The proxy resources included in the preferred portfolio consist of (1) a Utah wet-cooled gas combined-cycle plant with a summer capacity rating of 570 MW, acquired by the summer of 2014, and (2) a 261 MW east-side intercooled aeroderivative simple-cycle gas plant acquired by the summer of 2016 • Procure through activation of the suspended 2008 all-source RFP in late 2009 – The Company plans to submit Company resources (self-build or ownership transfers) once the suspension is removed • *In recognition of the unsettled U.S. economy, expected continued volatility in natural gas markets, and regulatory uncertainty, continue to seek cost-effective resource deferral and acquisition opportunities in line with near-term updates to load/price forecasts, market conditions, transmission plans, and regulatory developments.*
4	**Plant Efficiency Improvements**	**2009-2018**	Pursue economic plant upgrade projects—such as turbine system improvements and retrofits—and unit availability improvements to lower operating costs and help meet the Company's future CO_2 and other environmental compliance requirements • *Successfully complete the dense-pack coal plant turbine upgrade projects by 2016, which are expected to add 128 MW of incremental in the east and 42 MW in the West with zero incremental emissions* • *Seek to meet the Company's aggregate coal plant net heat rate improvement goal of 213 Btu/kWh by 2018*[55] • *Monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules*
5	**Class 1 DSM**	**2009-2018**	Acquire at least 200 - 300 MW of cost-effective Class 1 demand-side management programs for implementation in the 2009-2018 time frame • *Pursue up to 200 MW of expanded Utah Cool Keeper program participation by 2018* • *Pursue up to 130 MW of additional cost-effective class 1 DSM products(90 MW in the east side and 30*

[55] PacifiCorp Energy Heat Rate Improvement Plan, March 31, 2009.

Action Item	Category	Timing	Action(s)
			MW in the west side) to hedge against the risk of higher gas prices and a faster-than-expected rebound in load growth resulting from economic recovery Procure through the currently active 2008 DSM RFP and subsequent DSM RFPs • For 2009-2010, implement a standardized Class 1 DSM system benefit estimation methodology for products modeled in the IRP. The modeling will compliment the supply curve work by providing additional resource value information to be used to evolve current Class 1 products and evaluate new products with similar operational characteristics that may be identified between plans.
6	**Class 2 DSM**	**2009-2018**	Acquire 900 - 1,000 MW of cost-effective Class 2 programs by 2018 (peak capacity), equivalent to about 430 to 480 MWa • *Procure through the currently active DSM RFP and subsequent DSM RFPs*
7	**Class 3 DSM**	**2009-2018**	Acquire cost-effective Class 3 DSM programs by 2018 • *Procure programs through the currently active DSM RFP and subsequent DSM RFPs* • *Continue to evaluate program attributes, size/diversity, and customer behavior profiles to determine the extent that such programs provide a sufficiently reliable firm resource for long-term planning* • *Portfolio analysis with Class 3 DSM programs included as resource options indicated that at least 100 MW may be cost-effective; continue to evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling*
8	**Distributed Generation**	**2009-2018**	Pursue at least 100 MW of distributed generation resources by 2018 • *Procure at least 50 MW of combined heat and power (CHP) generation: 30 MW for the east side and 20 MW for the west side, to include purchase of facility output pursuant to PURPA regulations supply-side RFPs (renewable shelf RFPs and All Source RFPs, which provide for QFs with a capacity of 10 MW or greater), and other opportunities; focus on renewable fuel and other "clean" facilities to the extent that federal and state Renewable Production Tax credit rules provide additional Renewable Energy Credit value to such facilities* • *Procure at least 50 MW of cost-effective customer standby generation: 38 MW for the east side (subject to air permitting restrictions and other implementation constraints) and 12 MW for the west side. Procurement to be handled by competitive RFP for demand response network service and/or individual customer agreements* • Seek up to an additional 40 MW of customer standby generation if the economic recession and market conditions continue to support elimination of simple-cycle gas units or other peaking resources as indicated by IRP portfolio modeling for the 2010 business plan/2008 IRP update
9	**Planning Process**	**2009-2010**	Portfolio modeling improvements • Complete the implementation of System Optimizer capacity expansion model enhancements for

Action Item	Category	Timing	Action(s)
	Improvements		improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level • Continue to improve wind resource modeling by refining the representation of intermittent wind resources; attributes to consider include incremental reserve requirements and other components tied to system integration, geographical diversity impacts, and peak load carrying capability estimation • Refine modeling techniques for DSM supply curves/program valuation, and distributed generation • Investigate and implement, if beneficial, the Loss of Load Probability (LOLP) reliability constraint functionality in the System Optimizer capacity expansion model • Continue to coordinate with PacifiCorp's transmission planning department on improving transmission investment analysis using the IRP models • Continue to investigate the formulation of satisfactory proxy intermediate-term market purchase resources for portfolio modeling, contingent on acquiring suitable market data Establish additional portfolio development scenarios for the business plan that will be completed by the end of 2009, and which will support the 2008 IRP update • A federal CO_2 cap-and-trade policy scenario along the lines originally proposed for this IRP • Consider developing one or more scenarios incorporating plug-in electric vehicles and Smart Grid technologies
10	**Transmission**	**2009-2011**	Obtain Certificates of Public Convenience and Necessity for Utah/Wyoming/Northwest segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief • Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Mona To Oquirrh • Obtain Certificate of Public Convenience and Necessity for 230 kV and 500 kV line between Windstar and Populus • Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Populus and Hemingway
11	**Transmission**	**2010**	Permit and build Utah/Idaho/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief • Permit and construct a 345 kV line between Populus to Terminal
12	**Transmission**	**2012**	*Permit and build Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Mona and Oquirrh*

Action Item	Category	Timing	Action(s)
13	Transmission	2014	*Permit and build segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct 230 kV and 500 kV line between Windstar and Populus* • *Permit and construct a 345 kV line between Sigurd and Red Butte*
14	Transmission	2016	*Permit and build Northwest/Utah/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Populus and Hemingway*
15	Transmission	2017	*Permit and build Wyoming/Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Aeolus and Mona*

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 31ST DAY OF JULY 2009, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-09-06, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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