NEIL PRICE
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0314
BAR NO. 6864

Street Address for Express Mail:
472 W. WASHINGTON
BOISE, IDAHO 83702-5918

Attorney for the Commission Staff

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFICORP DBA ROCKY MOUNTAIN POWER'S 2011 INTEGRATED RESOURCE PLAN.	**CASE NO. PAC-E-11-10** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its attorney of record, Neil Price, Deputy Attorney General, and in response to the Notice of Filing and Notice of Modified Procedure issued in Order No. 32243 on May 13, 2011, submits the following comments.

BACKGROUND

On April 1, 2011, PacifiCorp dba Rocky Mountain Power ("PacifiCorp" or "Company") filed its 2011 Integrated Resource Plan (IRP) with the Commission pursuant to the Commission's rules and in compliance with the biennial IRP filing requirements mandated in Order No. 22299. PacifiCorp serves approximately 70,000 customers in southeastern Idaho. The Company provides electric service to more than 1,700,000 customers in Utah, Wyoming, Oregon, Washington, California and Idaho.

PacifiCorp's 2011 IRP was developed through a collaborative public process with participation from public stakeholders, including regulatory staff, advocacy groups, and other interested parties. The IRP, 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 2011 IRP include a finding of resource need, focusing on the 10-year period 2011-2020, 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 2011 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 unless otherwise stated.

The resource need accounts for load growth, sales obligations, existing resources, and a 13% planning reserve margin. Based on an October 2010 load forecast, PacifiCorp experiences a capacity deficit beginning in 2011, when the system will be short by 326 MW. Comparatively, the 2008 IRP forecasted deficits to also occur beginning in 2011, though at a higher level (498 MW). The Company attributes the difference to lower demand, especially in the industrial sector, due to the economic downturn. The deficit increases to 2,546 MW in 2015 and 3,852 MW by 2020. The capacity deficit is driven by a coincident system peak load growth rate of 2.1% for 2011-2020, taking into account energy efficiency savings. PacifiCorp's capacity position, which includes existing obligations, a 13% planning reserve, and reflects the loss of over 1,000 MW of expiring power purchase contracts, is shown below:

Table ES.1 – PacifiCorp 10-year Capacity Position Forecast (Megawatts)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
System										
Total Resources	12,468	11,802	11,810	11,404	11,399	11,397	11,412	11,433	11,395	11,192
System Obligation	11,497	11,973	12,264	12,256	12,403	12,595	12,728	12,961	13,145	13,376
Reserves (based on 13% target)	1,297	1,430	1,470	1,522	1,542	1,569	1,582	1,611	1,633	1,668
Obligation + 13% Planning Reserves	12,794	13,403	13,735	13,778	13,945	14,164	14,310	14,572	14,777	15,044
System Position	(326)	(1,601)	(1,925)	(2,373)	(2,546)	(2,767)	(2,898)	(3,139)	(3,383)	(3,852)

On an energy basis, the system begins to experience short positions during heavy load hours beginning in 2011, and on an annual basis in 2015. PacifiCorp's estimated energy need over the planning horizon is shown below:

Table A.9 – Annual Load forecasted (in Megawatt-hours) 2011 through 2020

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID*
2011	**63,131,207**	14,968,933	4,579,565	954,604	26,106,815	10,611,408	3,721,679	2,188,202
2012	**64,958,409**	15,487,788	4,676,478	969,067	26,746,468	11,040,464	3,804,258	2,233,885
2013	**66,388,259**	15,669,033	4,703,107	972,280	27,389,581	11,451,701	3,937,679	2,264,877
2014	**68,035,127**	15,853,824	4,754,379	982,164	28,151,361	11,883,924	4,106,332	2,303,143
2015	**69,442,054**	16,038,453	4,809,526	991,175	28,805,998	12,220,507	4,234,971	2,341,424
2016	**71,110,972**	16,283,652	4,880,687	1,002,320	29,650,389	12,548,966	4,357,547	2,387,412
2017	**72,151,300**	16,419,176	4,921,944	1,009,109	30,196,791	12,770,304	4,415,978	2,417,998
2018	**73,424,134**	16,602,014	4,977,007	1,018,716	30,840,594	13,055,537	4,473,968	2,456,298
2019	**74,713,621**	16,789,205	5,030,425	1,028,331	31,491,637	13,346,735	4,532,675	2,494,611
2020	**76,136,508**	16,998,651	5,089,930	1,039,248	32,188,156	13,680,764	4,598,606	2,541,153
				Average Annual Growth Rate				
2011-20	**2.1%**	**1.4%**	**1.2%**	**0.9%**	**2.4%**	**2.9%**	**2.4%**	**1.7%**
2021-30	**1.7%**	**0.9%**	**0.9%**	**0.8%**	**1.9%**	**2.5%**	**1.2%**	**1.4%**
2011-30	**1.9%**	**1.1%**	**1.1%**	**0.9%**	**2.1%**	**2.7%**	**1.8%**	**1.5%**

*SE-ID represents a contract with BPA that makes the Company responsible for BPA's south Idaho retail load.

To determine how best to address the capacity and energy deficits, PacifiCorp developed 67 input scenarios for portfolio development, and utilizing a number of resource optimization models and its own discretion in resource procurement, decided on a preferred portfolio it believes achieves "a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest." (2011 IRP, p. 19). The preferred portfolio of the new IRP contains a significant level of energy efficiency measures, new gas-fired combined-cycle combustion turbines (CCCTs) in 2014, 2016, and 2019, transmission additions, firm market purchases, and renewable resource additions throughout the planning horizon.

STAFF ANALYSIS

Staff has reviewed PacifiCorp's 2011 IRP and recognizes the Company's sustained efforts in developing a sophisticated, thorough planning document amid an uncertain economic backdrop. The Company continues to refine its modeling approach, specifically in regard to demand side resources, and capabilities to expand the analytical scope of the document. While the IRP does not take the place of the Company's annual ten-year business plan with respect to specific resource acquisition, the alignment of the two (instituted in 2008) provides stakeholders with a more transparent view of the planning process. Staff does not intend for its comments to be all-inclusive of the document, but rather will focus on a number of issues it deems important to the Company's ten-year action plan.

The economic planning environment continues to be stagnant when compared to the period used to develop PacifiCorp's 2009 IRP, which utilized a February 2009 load forecast. Both system peak and system load are projected to grow at an annual rate of 2.1% over the ten-year planning horizon.[1] These projected growth rates are high when compared to other utilities within the state and around the nation. For example, Idaho Power projected a 1.8% annual growth in system peak and 1.4% annual growth in average load in its 2011 IRP. Signs of load degradation within PacifiCorp's service territory appear to have diminished relative to the previous IRP filing, softening the reduction in forecasted load and peak. The Company cites growth in the residential and commercial sectors, mainly for the East-side of its system, and potential large new industrial customers (namely large data centers located around the Salt Lake City area) as other reasons load and peak continues to grow at a moderate pace over the planning horizon. Staff notes that predicting additional large new load during poor economic times is a risky proposition; for example, there is the possibility that at least one of the presumed new large customers may be delaying or abandoning their facility in Salt Lake City. Given long lead times on large generation facilities, such as the Lakeside 2 (CCCT) currently under construction, the Company may find itself long on capacity in the near-term, and in need of deviating from its Action Plan.

The 2011 forecast, developed in October 2010, nearly mimics that of the 2009 IRP update forecast[2], developed in November 2009. Both forecasts are lower than that used in the 2009 IRP throughout the timeframe. For planning purposes, the impact is greater on system peak than energy. In 2018, the comparable out-year of the forecasts, the Company predicts system coincident peak to be roughly 2.6%, or 328 MW, below that projected in the 2009 IRP, and system load to be roughly 1.2% lower than the 2009 IRP forecast. Staff does not believe the reductions are inconsequential, and may affect the timing of resource additions. That said, it does not appear that the relative magnitude of resource additions is materially affected over the IRP timeframe.

[1] Over the twenty-year horizon, system peak and loads are projected to grow at an average of 1.9% annually.
[2] PacifiCorp filed an update to the 2009 IRP on March 31, 2010. The 2009 IRP was filed with the Commission on May 29, 2009.

PacifiCorp notes that the political environment has changed since its last IRP filing. Though the various State initiatives governing climate change and renewable portfolio standards remain in place, there is a reduced likelihood for federal climate change legislation in the near-term. The Company continues to monitor developments at the federal level, and includes the impacts of carbon and greenhouse gas regulations in its portfolio modeling and selection process. Staff concurs that it is appropriate to consider the possibility of federal climate change legislation in its portfolio evaluation process, and is satisfied that the Company has adequately addressed the issue. PacifiCorp does recognize that there are potential consequences stemming from various EPA regulations on the operations of its generation fleet, especially its coal-fired facilities, which have prompted expenditures in pollution control equipment.

Price Forecasts

One other aspect of the planning paradigm that has changed since the 2009 IRP has been the significant decrease in natural gas and wholesale electricity prices. In recent years, market prices for electricity in the West have been tied closely to natural gas prices as gas-fired generation tends to be the marginal resource, especially during high load hours. This trend is predicted to continue in the foreseeable future.[3]

Staff acknowledges the recent decline in natural gas prices but notes that the fuel has shown significant volatility over the past ten years. PacifiCorp points out on page 27 of the 2011 IRP that day-ahead prices at Henry Hub have fluctuated between a low of $1.72 per MMBtu (November 16, 2001) to a high of $18.41 per MMBtu (February 25, 2003). Recently, prices have somewhat settled below $5.00 per MMBtu, presumably on the premise that demand is lower and domestic supplies from shale have increased. Many are optimistic that expansion of unconventional domestic supplies will continue to put downward pressure on gas prices. Staff is cautious to overestimate reliance on emerging natural gas resources. One need only to look a few years back when it was thought that liquefied natural gas would fill the supply-demand gap. Due to global competition and the increased domestic production, that has not materialized. Also, demand for natural gas can be presumed to grow significantly over the planning horizon, with the U.S. Energy Information Agency predicting

[3] To date, 2011 is running contrary to view, mainly due to extraordinarily high runoff throughout the Northwest and depressed loads associated with cooler weather and slower economic activity. In fact, there were periods during light load hours when wholesale prices at Northwest trading hubs dipped below $0 per MWh.

60% of electric generation from 2010-2035 will come from natural gas-fired facilities. Future volatility in natural gas prices increases the risk in variable fuel costs borne by customers.

Resource Options

Staff maintains that PacifiCorp continues to do an admirable job capturing the various operating characteristics and costs when screening resources in the modeling process. PacifiCorp relies on a number of third-party studies, along with its own experience, to estimate capital costs throughout the planning horizon. PacifiCorp evaluated a number of renewable resources for inclusion in portfolio modeling, including wind on the east and west sides of its system, geothermal, pumped storage, and various solar technologies. The Company notes that capital costs have generally decreased since 2009 due to the slowdown in the economy. Additionally, the Company states that certain unproven technologies, such as integrated gasification combined cycle (IGCC) plants and certain renewables display greater cost and operating uncertainty relative to more traditional resources. With much of its generating units located in solar-intensive areas, Staff encourages PacifiCorp to investigate the feasibility of augmenting or retrofitting its gas and coal facilities with a solar hybrid design in future IRPs. Aside from the benefits associated with utilizing the existing infrastructure, it is assumed that as these technologies mature, market conditions may accelerate reductions in capital costs.

PacifiCorp continues to refine its analysis of wind resources for portfolio modeling. In this IRP, adjustments were made to the topology bubbles to allow the System Optimizer model to select wind resources sited outside of transmission-constrained areas in Wyoming. Staff believes this adjustment provides greater flexibility for the model to select additional wind should it prove to be a preferred resource. These 'wind only' bubbles are also assigned an incremental transmission cost, which Staff considers appropriate to better approximate the true cost of wind resources. An adjusted wind resource cost is then determined for modeling purposes, taking into account capital, fixed O&M, wheeling and integration costs. Staff notes that the Company included a wind integration charge of $9.70/MWh in its analysis, a figure supported by its Wind Integration Study completed in September 2010. Staff believes that PacifiCorp is well-positioned to integrate wind given its resource diversity and geographic footprint.

The Company has done an excellent job developing its demand-side management (DSM) resources into distinct supply curve bundles to allow competitive model selection of DSM and supply-side resources. The basis for DSM development was a potential study conducted by the

Cadmus Group in 2007, which provided estimates of size, type, location and cost for resources that were updated using a 2009 study. Staff is aware that a recent potential study has been completed (March 2011), and recognizes that this information was not available at the time the 2009 IRP was created. Staff expects any new findings from the recent study will be incorporated in the 2011 IRP Update.

For the 2011 IRP, fifty discrete supply curves were developed for both Class 1 and Class 3 DSM.[4] PacifiCorp continued the practice introduced in its 2009 IRP of creating supply curves Class 2 DSM that are bundled by cost across each state within its jurisdiction.[5] In total, nine Class 2 DSM bundles were created for each state.[6] The System Optimizer model is capable of selecting any set of bundles throughout the twenty-year timeframe. Staff believes that the Company has adequately characterized supply and demand-side resources, as well as transmission options and market transactions, which leads to equitable treatment in the resource selection process.

Portfolio Modeling and Selection

As noted earlier, PacifiCorp created 67 portfolio cases or scenarios that cover an array of assumptions regarding, among other things, CO_2 regulation, natural gas prices, and alternative load forecasts. For this IRP, the Company specified several cases that evaluate partial and total construction of the Company's planned Energy Gateway Transmission Project (Gateway Project). The defined cases are then optimized in the Company's System Optimizer capacity expansion model to develop resource portfolios, which then go through a Monte Carlo production cost simulation to evaluate stochastic risk. Based on its assessments of costs and risks, PacifiCorp selects the top performing portfolios for further evaluation. The stochastic measures are broken into three categories:

1) Cost
   Mean present value of revenue requirements (PVRR),
   Risk adjusted mean PVRR, and
   10-year customer rate impact;

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[4] 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.

[5] 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. Class 2 DSM is bundled due to the voluminous permutations that could be generated from all potential programs.

[6] A tenth bundle, representing a compact florescent bulb program, was included for 2011 and 2012. Due to changes in Federal lighting standards, the bundle was not made available for selection in subsequent years.

2) Risk
 Upper-tail mean PVRR,
 5^{th} and 95^{th} percentile PVRR, and
 Production cost standard deviation; and

3) Supply reliability
 Average annual energy not served (ENS),
 Upper-tail ENS, and
 Loss of load probability

The selected portfolios then undergo further optimization to test for deterministic risk, such as varying gas and electricity prices for final portfolio selection, which is fine-tuned by the Company based on an "analysis of key resource acquisition and regulatory compliance risks." (2011 IRP, p. 202)

Staff notes that in this IRP, PacifiCorp included a 10-year customer rate impact measure of stochastic risk. According to the IRP, the "focus of the rate impact review [is] the stability of year-to-year percentage of full revenue requirement impacts, as well as the cumulative 10-year impact." (*Ibid*, p. 192) While results from this measure vary slightly from the other PVRR-based metrics, Staff believes it is appropriate to evaluate the approximate year-to-year impact of each portfolio. That said, Staff notes that this represents a year-to-year outlook on revenue requirement, and does not capture the yearly rate instability associated with volatile market prices and fuel costs captured in the Company's energy cost adjustment mechanism (ECAM).

After initial screening, the Company selected eight top performing portfolios for further evaluation. Upon review, two of the eight were selected for deterministic analysis.[7] It is unclear as to the criteria used by the Company to determine the portfolio finalists, as there was little difference in portfolio cost metrics (for example, there was less than a 1% difference in ratepayer impact for all but one of the portfolios under various scenarios), and the finalists performed near the bottom in carbon risk and supply availability. The Company needs to do a better job explaining its portfolio decisions when there does not appear to be clear best options.

The final screening consists of assessment for acquisition risk and environmental compliance risk mitigation. PacifiCorp adjusted the final portfolio to delay procurement of a CCCT in 2015 to 2016, citing undesirable rate impacts and corporate budgeting issues due to a planned CCCT

[7] Initially, three portfolios were selected for further analysis. Due to similarities between two of the portfolios, PacifiCorp opted to screen only two.

addition in 2014. The Company also removes 105 MW of geothermal resources (selected in all scenarios) due to development cost recovery uncertainty. A recent report by the Glacier Partners Corp. suggests that nearly 55% of construction costs are associated with exploration and drilling, and there is a high probability that a site may not be suited for utility-scale power production. If the utility expends the capital to develop a geothermal resource to no avail, it risks disallowance of recovery in rates by regulators. PacifiCorp states that until there is a clear signal from regulators on cost recovery, it views geothermal as an alternate resource to procure, but not one to include in its IRP.

The geothermal resources were replaced with an equivalent amount of wind for final screening.[8] Staff does not consider the two resources to be similar in any manner other than being considered 'renewable.' Wind is an intermittent resource with a low capacity factor, and contributes little to the Company's capacity need. Geothermal is considered a baseload resource due to its high capacity factor and reliability. Staff does not believe the portfolio selection process accurately captures these dissimilarities. Given the extreme operating differences between wind and geothermal, Staff wonders to what extent the final portfolio determination is affected by this ad hoc adjustment so late in the process. Staff expects the Company will refine its approach toward treatment of geothermal resources in future IRP filings.

As a way to mitigate the impact of more stringent renewable resource policies, the Company then opted to increase the quantity of wind to 2,100 MW. The basis for this value was an average of the top three performing portfolios under alternate CO2 tax scenarios. It should be noted that only one of the eight portfolios from the initial screening cut was included in the calculation, and none from those selected for further screening. Based on what it considers a reasonable acquisition schedule, the Company fixed the wind resource availability and amount to the 2018 through 2029 timeframe. With these adjustments, PacifiCorp re-optimized the portfolio to determine what it considers the preferred portfolio shown below:

[8] Using capacity factors for each resource, the Company was able to calculate 572 MW of equivalent wind, which was added to 139 MW included in the finalist portfolio.

	Capacity (MW)																				Total,
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	20-year
CCCT F Class	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222
CCCT H Class	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475
Coal Plant Turbine Upgrades	12	19	6	-	-	18	-	8	-	-	2	-	-	-	-	-	-	-	-	-	65
Wind, Wyoming	-	-	-	-	-	-	-	300	300	200	200	200	200	200	100	100	100	100	100	-	2,100
CHP - Biomass	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	104
DSM, Class 1	6	70	57	20	97	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	255
DSM, Class 2	108	114	110	118	122	124	126	120	122	125	125	134	133	139	140	146	136	135	141	145	2,563
Oregon Solar Programs	4	4	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
Micro Solar - Water Heating	-	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	-	-	30
Front Office Transactions	350	1,240	1,429	1,190	1,149	775	822	967	695	995	700	750	750	750	750	750	750	750	750	750	N/A
Growth Resources	-	-	-	-	-	-	-	-	-	-	11	95	201	250	546	717	863	975	1,150	1,265	N/A

Note: Front office transaction (firm market purchases) and growth resources reflect one-year transaction periods, and are not additive. Growth resources are similar to front office transactions, but are located in load areas as opposed to being purchased at market hubs, and represent generic capacity needed to meet planning reserve margins in the latter half of the IRP planning period.

The preferred portfolio represents PacifiCorp's best efforts to meet its obligations in a low-cost manner when accounting for various sources of risk and uncertainty. While the process may not be completely transparent, Staff believes the Company utilized its best judgment given the most current information in developing this portfolio.

2011 IRP Action Plan

PacifiCorp's 2011 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. In the near term, PacifiCorp plans to issue a Request for Proposals (RFP) for a baseload facility that corresponds with the identified 597 MW CCCT identified in the preferred portfolio to go along with the 637 MW Lakeside 2 plant, due online in 2014. The Company intends to acquire 80 MW of Class 1 DSM in the 2012-2013 timeframe, with the remaining 170 MW acquired over the next ten years. The Company indicates that it will acquire 1,200 MW of Class 2 DSM through an ongoing DSM RFP process. Based on the portfolio results, the Company will pursue 800 MW of wind resources by 2020, and steadily add more wind over the next nine years.

PacifiCorp includes a separate transmission expansion action plan in the 2011 IRP, which details the continuing efforts toward completion of the Gateway Project. The Company has broken the transmission project into eight segments, listed below:

Segment Name	Segment Notation	Description	Planned In-Service Date
Wallula to McNary	A	230 kV, single circuit	2012-2013
Mona to Limber Limber to Oquirrh Oquirrh to Terminal	C	500 kV, single circuit 345 kV, double circuit 345 kV, double Circuit	2013 2013 2014
Windstar to Aeolus Aeolus to Populus	D	2-230 kV, single circuit 500 kV, single circuit	2015-2017
Populus to Hemingway	E	500 kV, single circuit	2015-2018
Aeolus to Mona	F	500 kV, single circuit	2017-2019
Sigurd to Red Butte	G	345 kV, single circuit	2014
Hemingway to Capitan Jack	H	500 kV, single circuit	unknown

A map showing the general locations of the projects is included as Attachment B of Staff's comments. Of the eight, three segments (A, C, G) are well into the permitting process, and have anticipated online dates in the 2012-2014 timeframe. Three more (D, E, F) are in initial scoping or permitting status, with estimated online dates ranging from 2014 to 2019. The Company has partnered with Idaho Power on segments D and E. A final segment (H) is currently under review as to the most economic strategy for development, *i.e.*, should the Company partner with other utilities (namely Idaho Power and Portland General Electric) for joint development and ownership of the project or self-build and maintain sole ownership.[9] Staff will continue to monitor the Company's progress toward completion of the Gateway Project, and fully expects the Company to continue to evaluate the economics of the endeavor.

Prudency assessment or approval of specific resources cited in either action plan is beyond the scope of the IRP review. Staff and the Commission will address such issues in a more suitable forum, such as a general rate case. While not endorsing the selected portfolio, Staff nonetheless believes the identified course of action seems reasonable given the assumptions, analysis and conclusions of the Company as presented in the IRP.

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. I n 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.

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[9] The segment not listed is the Populus to Terminal line, which was completed prior to submission of the 2011 IRP.

STAFF RECOMMENDATIONS

Staff believes that the Company has adequately met the Commission's requirements in regard to the 2011 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 2011 IRP.

Respectfully submitted this 11th day of July 2011.

Neil Price
Deputy Attorney General

Technical Staff: Bryan Lanspery

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Table 9.1 – IRP Action Plan Update

Action items anticipated to extend beyond the next two years, or occur after the next two years, are indicated in blue italic font. Transmission action plan items have been moved to Chapter 10, Transmission Action Plan.

Action Item	Category	Timing	Action(s)
1	**Renewables/ Distributed Generation**	**2011-2020**	<u>Wind</u> • ***Acquire up to 800 MW of wind resources by 2020, dictated by regulatory and market developments such as (1) renewable/clean energy standards, (2) carbon regulations, (3) federal tax incentives, (4) economics, (5) natural gas price forecasts, (6) regulatory support for investments necessary to integrate variable energy resources, and (7) transmission developments. The 800-megawatt level is supported by consideration of regulatory compliance risks and public policy interest in clean energy resources.*** <u>Geothermal</u> • The Company identified over 100 MW of geothermal resources as part of a least-cost resource portfolio. Continue to refine resource potential estimates and update resource costs in 2011-2012 for further economic evaluation of resource opportunities. Continue to include geothermal projects as eligible resources in future all-source RFPs. <u>Solar</u> • Evaluate procurement of Oregon solar photovoltaic resources in 2011 via the Company's solar RFP. • ***Acquire additional Oregon solar resource through RFPs or other means in order to meet the Company's 8.7 MW compliance obligation.*** • Work with Utah parties to investigate solar program design and deployment issues and opportunities in late 2011 and 2012, using the Company's own analysis of Wasatch Front roof top solar potential and experience with the Oregon solar pilot program. As recommended in the Company's response to comments under Docket No. 07-035-T14, the Company requested that the Utah Commission establish "a process in the fall of 2011 to determine whether a continued or expanded solar program in Utah is appropriate and how that program might be structured."[74] • ***Investigate, and pursue if cost-effective from an implementation standpoint, commercial/residential solar hot water heating programs.*** – ***The 2011 IRP preferred portfolio includes 30 MW of solar hot water heating resources by 2020 (18 MW in the east side and 12 MW in the west side).*** <u>Combined Heat & Power (CHP)</u> • ***Pursue opportunities for acquiring biomass CHP resources, primarily through the PURPA Qualifying Facility contracting process.***

[74] Rocky Mountain Power, "Re: Docket No. 07-035-T14 – Three year assessment of the Solar Incentive Program", December 15, 2010.

Attachment A
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Action Item	Category	Timing	Action(s)
			– ***The preferred portfolio contains 52 MW of CHP resources for 2011-2020 (10 MW in the east side and 42 MW in the west side)*** Energy Storage • Proceed with an energy storage demonstration project, subject to Utah Commission approval of the Company's proposal to defer and recover expenditures through the demand-side management surcharge. • Initiate a consultant study in 2011 or 2012 on incremental capacity value and ancillary service benefits of energy storage. Renewable Portfolio Standard Compliance • Develop and refine strategies for renewable portfolio standard compliance in California and Washington.
2	**Intermediate / Base-load Thermal Supply-side Resources**	**2014-2016**	• Acquire a combined-cycle combustion turbine resource at the Lake Side site in Utah by the summer of 2014; the plant is proposed to be constructed by CH2M Hill E&C, Inc. ("CH2M Hill") under the terms of an engineering, procurement, and construction (EPC) contract. This resource corresponds to the 2014 CCCT proxy resource included in the 2011 IRP preferred portfolio. • Issue an all-source RFP in late 2011 or early 2012 for acquisition of peaking/intermediate/baseload resources by the summer of 2016. – This acquisition corresponds to the 597 MW 2016 CCCT proxy resource (F Class 2x1). • PacifiCorp will reexamine the timing and type of post-2014 gas resources and other resource changes as part of the 2011 business planning process and preparation of the 2011 IRP Update. – ***Consider siting additional gas-fired resources in locations other than Utah. Investigate resource availability issues including water availability, permitting, transmission constraints, access to natural gas, and potential impacts of elevation.***
3	**Firm Market Purchases**	**2011-2020**	• Acquire up to 1,400 MW of economic front office transactions or power purchase agreements as needed until the beginning of summer 2014, unless cost-effective long-term resources are available and their acquisition is in the best interests of customers. – Resources will be procured through multiple means, such as periodic mini-RFPs that seek resources less than five years in term, and bilateral negotiations. • ***Closely monitor the near-term and long-term need for front office transactions and adjust planned acquisitions as appropriate based on market conditions, resource costs, and load expectations.***
4	**Plant Efficiency Improvements**	**2011-2020**	• Continue to 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 scheduled for 2011 and 2012, totaling 31 MW.

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Action Item	Category	Timing	Action(s)
			– ***Complete the remaining turbine upgrade projects by 2021, totaling an incremental 34.2 MW, subject to continuing review of project economics.*** – ***Seek to meet the Company's updated aggregate coal plant net heat rate improvement goal of 478 Btu/kWh by 2019.***[75] – ***Continue to monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules.***
5	**Class 1 DSM**	**2011-2020**	Acquire up to 250 MW of cost-effective Class 1 demand-side management programs for implementation in the 2011-2020 time frame. • For 2012-2013, pursue up to 80 MW of the commercial curtailment product (which includes customer-owned standby generation opportunities) being procured as an outcome of the 2008 DSM RFP. • ***Depending on final economics, pursue the remaining 170 MW for 2012-2020, consisting of additional curtailment opportunities and irrigation/residential direct load control.***
6	**Class 2 DSM**	**2011-2020**	• ***Acquire up to 1,200 MW of cost-effective Class 2 programs by 2020, equivalent to about 4,533 GWh. This includes programs in Oregon acquired through the Energy Trust of Oregon.*** – ***Procure through the currently active DSM RFP and subsequent DSM RFPs.*** • Apply the 2011 IRP conservation analysis as the basis for the Company's next Washington I-937 conservation target setting submittal to the Washington Utilities and Transportation Commission for the 2012-2013 biennium. The Company may refine the conservation analysis and update the conservation forecast and biennial target as appropriate prior to submittal based on final avoided cost decrement analysis and other new information. • ***Leverage the distribution energy efficiency analysis of 19 distribution feeders in Washington (conducted for PacifiCorp by Commonwealth Associates, Inc.) for analysis of potential distribution energy efficiency in other areas of PacifiCorp's system. (The Washington distribution energy efficiency study final report is scheduled for completion by the end of May 2011.)***
7	**Class 3 DSM**	**2011-2020**	• Continue to evaluate Class 3 DSM program opportunities. – Evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling[76], and monitor market changes that may remove the voluntary nature of Class 3 pricing products.

[75] *PacifiCorp Energy Heat Rate Improvement Plan*, April 2010.
[76] Supply curve development indicates that when the stacking effect of Class 1 and Class 3 resource interactions are considered, the selected resources within both Classes of DSM diminish.

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Action Item	Category	Timing	Action(s)
8	**Planning and Modeling Process Improvements**	**2011-2012**	• Continue to refine the System Optimizer modeling approach for analyzing coal utilization strategies under various environmental regulation and market price scenarios. • Continue to coordinate with PacifiCorp's transmission planning department on improving transmission investment analysis using the IRP models. • Incorporate plug-in electric vehicles and Smart Grid technologies as a discussion topic for the next IRP. • Continue to refine the wind integration modeling approach; establish a technical review committee and a schedule and project plan for the next wind integration study.

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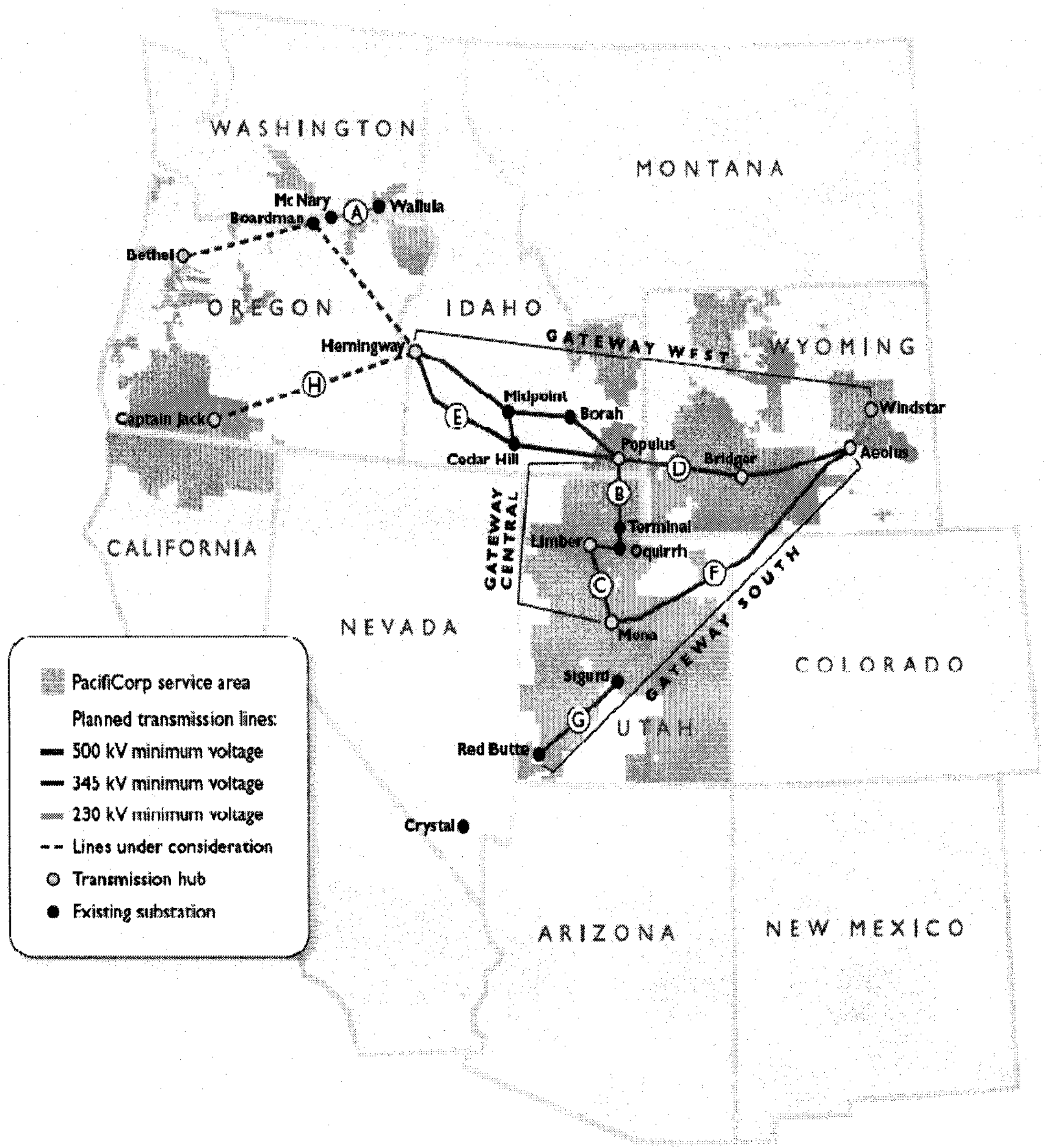
Energy Gateway Transmission Expansion Project



This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

November 2010

Attachment B
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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS **11TH** DAY OF JULY 2011, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-11-10, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

TED WESTON
ID REGULATORY AFFAIRS MGR
ROCKY MOUNTAIN POWER
201 S MAIN ST STE 2300
SALT LAKE CITY UT 84111
E-MAIL: ted.weston@pacificorp.com

DANIEL E SOLANDER
REGULATORY COUNSEL
ROCKY MOUNTAIN POWER
201 S MAIN ST STE 2300
SALT LAKE CITY UT 84111
E-MAIL: daniel.solander@pacificorp.com

DATA REQUEST RESPONSE CENTER
E-MAIL ONLY:
datarequest@pacificorp.com

Gloria D. Koch
SECRETARY