ORDER NO. 12 082

ENTERED MAR 09 2012

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 52

In the Matter of PACIFICORP 2011 Integrated Resource Plan.	ORDER

DISPOSITION: 2011 INTEGRATED RESOURCE PLAN WITH REVISED ACTION PLAN ACKNOWLEDGED WITH EXCEPTIONS AND GUIDANCE FOR NEXT IRP

I. OVERVIEW

PacifiCorp seeks acknowledgement of the company's 2011 Integrated Resource Plan (2011 IRP), as modified by a Revised Action Plan. The filings were made in accordance with Order No. 07-002[1] mandating that all regulated energy utilities operating in Oregon engage in integrated resource planning.[2]

We acknowledge the company's 2011 IRP and the company's Revised Action Plan, with three exceptions. We also direct PacifiCorp to engage in workshops with Staff and other parties to address certain planning and model improvements for PacifiCorp's next planning cycle.

A. Requirements for Integrated Resource Planning

We require regulated energy utilities to prepare and file integrated resource plans within two years after acknowledgment of a utility's last plan. Substantively, we require that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create an action plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies. See Order No. 07-002.

We acknowledge a utility's IRP to the extent the plan satisfies the procedural and substantive requirements of the guidelines set forth in Order No. 07-002, and the plan is

[1] Order No. 07-047 made corrections to Order No. 07-002 (Docket UM 1056).
[2] The Commission originally adopted least-cost planning in Order No. 89-507 (Docket UM 180). The Commission updated the utility planning process in Docket UM 1056.

deemed reasonable at the time of acknowledgement. Acknowledgement does not constitute a determination on the rate-making treatment of any resource acquisitions or other expenditures undertaken by the utility. As a legal matter, we must reserve judgment on all rate-making issues.[3] Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged IRP action plans. Utilities will also be expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

B. Jurisdiction and Procedural History

As a public utility in Oregon that provides electric service to the public, PacifiCorp is subject to the jurisdiction of the Commission and the Commission's integrated resource planning requirements. PacifiCorp's 2008 IRP, the company's last filed IRP, was acknowledged by the Commission (with an exception) in Order No. 10-066, entered on February 24, 2010.

On March 31, 2011, PacifiCorp filed its 2011 IRP. A prehearing conference was held on May 9, 2011, and a schedule was adopted. Petitions to intervene were granted on behalf the following parties: the Industrial Customers of Northwest Utilities (ICNU); Renewable Northwest Project (RNP); Oregon Department of Energy (ODOE); the Community Action Partnership of Oregon; Portland General Electric Company (PGE); NW Energy Coalition (NWEC); and the Sierra Club. The Citizens' Utility Board (CUB) intervened as a matter of right.

On June 27, 2011, PacifiCorp filed an addendum to its 2011 IRP. On August 9, 2011, a technical workshop was held for parties in the docket. PacifiCorp presented its IRP to the Commission at a Special Public Meeting on August 19, 2011. Staff and other parties filed opening comments on August 25, 2011. The company filed reply comments on September 21, 2011, along with a Supplemental Coal Replacement Study. Staff's final comments and a draft proposed order were filed on October 13, 2011. Comments in reply to Staff's final comments were filed by PacifiCorp and other parties on November 3, 2011. Staff's report and a revised draft proposed order were filed December 1, 2011.

At a public meeting held on December 6, 2011, concerns about PacifiCorp's 2011 IRP were discussed. In response to these concerns, PacifiCorp met with Staff and other parties following the public meeting. On January 9, 2012, PacifiCorp filed a Revised Action Plan for its 2011 IRP, and asked the Commission to acknowledge the company's 2011 IRP with the Revised Action Plan. PacifiCorp represented support for the Revised Action Plan from Staff, CUB, NWEC, RNP, and Sierra Club. Recognizing that not all parties had formally agreed to the Revised Action Plan, PacifiCorp asked for a comment period. ICNU was the only party that filed comments on the Revised Action Plan on January 17, 2012.

[3] *See* Order No. 07-002 at 24.

II. DISCUSSION

A. 2011 IRP Overview

PacifiCorp's 2011 IRP proposes a series of future actions that the company contends will be needed to ensure the future provision of reliable utility service at reasonable cost with manageable risk to customers. PacifiCorp represents that the IRP was developed with participation from numerous public stakeholders, including regulatory staff, advocacy groups, and other interested parties. PacifiCorp also contends that the process and substances of the IRP meet applicable state IRP standards and guidelines.

In its IRP, PacifiCorp forecasts a need for a significant amount of new resources to offset load growth and the expiration of long-term purchase power contracts occurring over the next several years. Without new resources, PacifiCorp states its system will experience a capacity deficit of 326 MW in 2011, and 3,852 MW by 2020. PacifiCorp bases its capacity need on a system annual peak load growth rate of 2.1 percent on a compounded average annual basis and a 13 percent planning reserve margin applied to load and wholesale sales obligations. PacifiCorp states that, on an average monthly energy basis, the system begins to experience short positions for heavy load hours in 2011. On an average annual basis, PacifiCorp reports that short positions occur by 2015. PacifiCorp bases its energy need on a system-wide average load growth rate of 1.8 percent per year.

PacifiCorp identified many key drivers that guided the 2011 IRP process. These include:

- Decreases in projected natural gas and wholesale electricity prices relative to the 2008 and 2009 forecasts.
- Uncertainty regarding federal efforts to develop comprehensive federal energy and climate change compliance requirements with robust public and legislative support for clean energy policies at the state level.
- Continued aggressive efforts by the U.S. Enviromnental Protection Agency to regulate electric utility plant emissions, including greenhouse gases, criteria pollutants, and other emissions.
- Expectations for a more favorable economic enviromnent than assumed in 2009.
- Progress and challenges in planning for, permitting, and building transmission projects.
- Near-term procurement activities, including the planned acquisition of a gas-fired combined-cycle combustion turbine plant in Utah with a 2014 in-service date.

B. Portfolio Analysis and Action Plan

PacifiCorp developed a variety of resource portfolios that included supply-side generation, demand-side management, and transmission. The Company defined 67 input scenarios for portfolio development that included alternative (1) transmission configurations, (2) CO2 tax levels and regulation types, (3) natural gas prices, (4) regulatory renewable acquisition requirements, (5) load forecasts, (6) renewable generation cost and acquisition incentives, and (7) demand side management (DSM) resource availability assumptions. PacifiCorp reports that it also conducted proof-of-concept modeling of coal unit replacements with combined-cycle combustion turbine (CCCT) alternatives, incorporating incremental costs for existing coal plants.

PacifiCorp identified top-performing portfolios based on a combination of lowest average portfolio cost and worst-case portfolio cost resulting from 100 Monte Carlo simulation runs. During final preferred portfolio selection PacifiCorp considered additional criteria such as risk-adjusted portfolio cost, the 10-year customer rate impact, CO2 emissions, supply reliability, resource diversity, and future uncertainty and risk of greenhouse gas and renewable portfolio standard (RPS) policies.

Based on that analysis, PacifiCorp selected a preferred portfolio and developed a 2011 IRP Action Plan. Among other things, the original action plan included the acquisition of up to 1,400 MW of front office transactions or power purchase agreements as needed until 2014, a CCCT resource by 2014, and up to 800 MW of wind resources by 2020. The Action Plan also included further evaluation of additional renewable resources and distributed generation, as well as up to 250 MW of Class 1 demand-side management programs during 2011-2020, and up to 1,200 MW of Class 2 DSM programs by 2020.

C. Objections to PacifiCorp's 2011 IRP

As noted above, Staff and the other parties raised numerous issues with, and provided considerable commentary on, certain aspects and elements of the original Action Items in PacifiCorp's original 2011 IRP Action Plan. The Commission also expressed concerns with aspects of the 2011 IRP at the public meeting held on December 6, 2011. Those disputes primarily focused on the following issues:

1. Coal Utilization Study

Staff, CUB, ODOE, the Sierra Club, RNP, and NWEC criticized the lack of a comprehensive analysis of the costs to upgrade PacifiCorp's coal plants for environmental compliance compared to the costs to retire the coal plants and invest in other resources. These parties emphasized the financial risks associated with investing in aging coal plants and the uncertainties about the scope of potential environmental regulations. Although PacifiCorp filed a Supplemental Coal Replacement Study, Staff and parties continued to have concerns about the sufficiency of the analysis supporting the conclusion that the continued operation of the company's coal fleet, with planned incremental investments, contributes to a resource strategy with the best combination of cost and risk for the utility and its customers.

2. Energy Efficiency (Class 2 DSM)

Class 2 DSM savings are achieved by installing more energy efficient equipment, appliances, lighting, and structures. Staff and other parties, including CUB and NWEC, expressed concerns that PacifiCorp is underestimating the amount of, and speed with which, energy efficiency can be achieved in states other than Oregon in the company's service territory. These parties worry that underestimating energy efficiency gains results in PacifiCorp proposing the development of a supply side resource unnecessarily early, which would result higher costs and risks for the utility and its ratepayers.

3. Load Control and Price Response Resources (Classes 1 and 3)

Class 1 DSM is dispatchable load control, scheduled irrigation and thermal energy storage. Class 3 DSM address system reliability and includes programs such as peak pricing, curtailable rates, and demand buy-back. Staff and NWEC criticized PacifiCorp for not committing to acquire more of the identified Class 1 DSM resources and any of the identified Class 3 DSM resources.

4. Distribution Energy Efficiency

In Order No. 10-066, the Commission directed PacifiCorp to incorporate an assessment of distribution system energy efficiency potential in its next IRP. Staff took the position that PacifiCorp's 2011 IRP failed to comply with this direction because although PacifiCorp's study of conservation voltage reduction (CVR) in Washington state indicated that this form of distribution system energy efficiency is cost-effective, the company failed to consider this resource on a system-wide basis and failed to include CVR in the preferred portfolio.

5. Planning and Modeling Process Improvements

Staff and other parties pointed out several planning and modeling limitations of PacifiCorp's 2011 IRP. For example, Staff, ICNU, and ODOE expressed concern about PacifiCorp's 13 percent target capacity planning reserve margin (PRM), arguing that a 12 percent PRM should be used instead. Staff and ICNU also identified shortcomings of PacifiCorp's Loss of Load Probability Study.

6. Need for a 2016 Combined Cycle Combustion Turbine Resource

Staff, CUB, RNP, and the Sierra Club all criticized the analysis underlying PacifiCorp's assertion that a new CCCT is the best resource to meet the company's capacity need starting in 2016. The parties asserted that PacifiCorp should consider whether peak capacity requirements could be met through other means, such as a combination of increased DSM and market purchases, or more flexible, less costly simple cycle combustion turbines.

D. Revised Action Plan

Following the public meeting, PacifiCorp held meetings with Staff and other parties to more fully discuss the issues. As a result of these discussions, PacifiCorp filed a Revised 2011 IRP Action Plan, attached as Appendix A to this order, which makes significant changes to the company's original action plan.[4] The Revised Action Plan was filed by

[4] *See* Table 9.1 of PacifiCorp's 2011 IRP (Mar 31, 2011).

PacifiCorp with the support of Staff, CUB, NWEC, RNP, and the Sierra Club. ICNU also supports the Revised Action Plan. No other party objects to any part of the Revised Action Plan.

The changes to PacifiCorp's 2011 IRP documented in the Revised Action Plan are comprehensive in nature, and largely address many of the concerns raised throughout this proceeding by Staff and other parties. For example:

- Action Item 9 was added to address the parties' concerns about PacifiCorp's coal utilization study. Pursuant to the new action item, PacifiCorp committed to host a technical workshop for stakeholders and the Commissioners to present the methodology, assumptions, and results of analysis for certain emission control investments and for Coal Replacement Study analysis for certain plants. The company will also include a revised Coal Replacement Study in its 2011 IRP Update.

- The Revised Action Plan establishes more specific commitments to obtain for Class 1 and Class 2 DSM resources. For Class 1 DSM resources, PacifiCorp commits to acquire at least 140 MW by 2013 and up to 250 MW by 2015. PacifiCorp will also complete an analysis of the economic feasibility of Class 1 irrigation load control in the west by the second quarter of 2012, with additional requirements based on results of the analysis. PacifiCorp commits to acquire at least 90 MW and up to 1,800 MW of cost-effective Class 2 programs by 2020, and at least 520 MW, and up to 1000 MW of cost-effective Class 2 DSM by 2015, and 900 MW Class 2 DSM by 2020.

- Among actions identified for Class 3 DSM, PacifiCorp will implement residential information pilots in Utah and Washington to test the effects of providing customers greater amounts of usage information on the quantity of electricity consumed.

- PacifiCorp will reexamine, in its 2011 IRP Update, the timing and type of post-2014 gas resources to add. PacifiCorp will issue an all-source RFP early in 2012 to potentially acquire peaking/intermediate/baseload resources by the summer of 2015. PacifiCorp also commits to actively search for market options that could cost-effectively defer a 2016 CCCT resource.

- For the 2011 IRP Update, PacifiCorp will include the results of a System Optimizer portfolio sensitivity analysis comparing the resource and cost impacts of a 12 percent versus 13 percent planning reserve margin.

E. Commission Consideration

With the exceptions noted below, we find PacifiCorp's 2011 IRP, as modified by the Revised Action Plan, to be reasonable at this time of review and to satisfy the procedural and substantive requirements of the guidelines set forth in Order No. 07-002. Accordingly, we acknowledge PacifiCorp's 2011 IRP with one clarification and three exceptions that we separately discuss below. We also provide PacifiCorp additional directives for its next IRP.

Before turning to the clarification, exceptions, and directives, we first want to commend the parties for working together to draft and agree to revised action items in the Revised Action Plan. We appreciate PacifiCorp's efforts to work collaboratively with Staff and the parties to address a significant number of concerns raised during the IRP acknowledgment process.

Moreover, we support PacifiCorp's plan to proceed with development and implementation of an energy storage demonstration project in the state of Utah. We strongly encourage PacifiCorp to evaluate energy storage options capable of addressing the summer peak in Utah as a means of delaying the need for a new thermal resource on the company's eastern system.

1. Clarification – Action Item 2

With regard to the plans outlined in Action Item 2 regarding the potential future acquisition of thermal resources, we share ICNU's understanding that the Revised Action Plan contemplates a comprehensive 2011 IRP Update that broadly analyzes the potential need for a new thermal resource, including updated load and resource forecasts, revised planning margins, revised estimates of conservation and demand side resources, revised analyses of front office transaction purchases, and the Plan provides a full opportunity for Staff and parties to conduct discovery and provide commentary. With that clarification, we acknowledge Action Item 2.

2. Exceptions – Action Item 1

Action Item 1 of the Revised Action Plan addresses PacifiCorp's resource development plans for a range of renewable resources, including wind, geothermal, solar, and combined heat and power (CHP). As written, however, the development plans for wind, geothermal and CHP resources are too indeterminate and insubstantial for us to acknowledge.

a. *Wind Resources*

The statement in Action Item 1 regarding wind resources that PacifiCorp will "[a]cquire up to 800 MW of wind resources by 2020" does not actually pledge any near-term action to acknowledge. The phrase "up to 800 MW" provides an upper limit, but not a meaningful target, on the amount of wind resources to be acquired. The phrase "by 2020" makes it impossible to determine what, if any, action PacifiCorp plans to take in the near-term. As written, PacifiCorp makes no commitment to acquire ***any*** wind resources between now and the year 2020. The purpose of an action plan is to identify specific near-term actions that the company plans to take to meet its resource needs. We will not acknowledge actions that are open-ended and too far in the future to be meaningful. We do not acknowledge Action Item 1 in the Revised Action Plan as it relates to wind resources. We will consider revisions in PacifiCorp's 2011 IRP Update to

Action Item 1 that concisely state the near-term actions the company will take to acquire wind resources.

b. Geothermal Resources

Action Item 1 regarding geothermal resources states that PacifiCorp has identified over 100 MW of geothermal resources as part of a least-cost resource portfolio, promises to continue evaluating the economics of geothermal resources, and to classify geothermal projects as an eligible resource in any future all-source RFP. This action item fails to state any specific near-term actions the company plans to take to acquire geothermal resources. The on-going evaluation of geothermal resources is a substantive requirement of the IRP, and we decline to acknowledge actions that are already required by our IRP guidelines or that we consider to be part of prudent utility practice.

We do not acknowledge Action Item 1 in the Revised Action Plan as it relates to geothermal resources. We will consider revisions in PacifiCorp's 2011 IRP Update to Action Item 1 that concisely state the near-term actions the company will take to acquire geothermal resources.

c. CHP

The statement in Action Item 1 regarding CHP that PacifiCorp will "[p]ursue opportunities for acquiring biomass CHP resources," expresses an aim but not a plan. Although PacifiCorp identifies 52 MW of CHP resources for the 2011-2020 time period in its preferred portfolio, PacifiCorp does not delineate a meaningful acquisition strategy that we can acknowledge.

We do not acknowledge Action Item 1 in the Revised Action Plan as it relates to CHP resources. Again, we will consider revisions in PacifiCorp's annual IRP Update to Action Item 1 that concisely state the near-term actions the company will take to acquire CHP resources.

3. Guidance for Next IRP Cycle

We direct PacifiCorp to continue the discussions with Staff and other parties, started during review of the company's 2011 IRP, to prepare for the company's next IRP cycle. In particular, we direct PacifiCorp to convene two workshops to address concerns in two related areas.

The first workshop should address the development of candidate resource portfolios for the next IRP. PacifiCorp currently uses the System Optimizer model to develop the candidate resource portfolios it will consider in an IRP. The company identifies future scenarios comprised of key model inputs and the System Optimizer model selects an "optimal" resource portfolio for each scenario. We are concerned that the resource portfolio with the best combination of cost and risk for the utility and its ratepayers may not be "optimal" for any one particular scenario. In other words, the best portfolio may be one that performs well across a wide range of future scenarios but is not "optimal" for any one scenario. We are concerned that the process used by PacifiCorp to develop candidate resource portfolios may be limiting the diversity of portfolios considered in the IRP.

The second workshop should address the development of the company's load and resource balances for both capacity and energy and the appropriate capacity planning reserve margin. The workshop should also address the development of an IRP action plan that identifies the contribution of each planned resource to the company's capacity and energy balances. In PacifiCorp's IRP it is often difficult to identify the contribution of each planned resource to the energy balance. Our overall concern is that it is difficult to identify how the planned resource actions are matched to meeting the capacity and energy needs of the company. We encourage PacifiCorp to continue to work with Staff and other parties to make improvements to its IRP in these key areas.

III. ORDER

IT IS ORDERED that the 2011 Integrated Resource Plan filed by PacifiCorp on March 31, 2011, as modified by the Revised Action Plan filed by PacifiCorp on January 9, 2012, and attached as Appendix A is acknowledged in accordance with the terms of this order.

Made, entered, and effective MAR 09 2012.

John Savage
Commissioner

Susan K. Ackerman
Commissioner

Stephen M. Bloom
Commissioner

ORDER NO. 12 082

Revised Action Plan - Clean

Table 9.1 – IRP Revised Action Plan Update

Action Item	Category		Action(s)
1	**Renewables/ Distributed Generation**		**<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. • In the next IRP, PacifiCorp will track and report the statistics used to calculate capacity contribution from its wind resources as a means of testing the validity of the PLCC method. • Future IRP cycles will include a projection for wind acquisition with and without geothermal until a clearer picture emerges regarding geothermal dry hole risk. • The Company will continue to refine the wind integration modeling approach; establish a technical review committee (TRC) and a schedule and project plan for the next wind integration study. The TRC will be formed and members identified within 30 days of the effective date of the IRP Order. Within 30 days of the effective date of the IRP Order, a schedule for the study will be established, including full opportunity for stakeholder involvement and progress reviews by the TRC that will allow the final study to be submitted with the next IRP. **<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 explicitly 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."[1]

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

ORDER NO. 12 082

APPENDIX A
PAGE 2 OF 5

Action Item	Category		Action(s)

			• Investigate, and pursue if cost-effective from an implementation standpoint, commercial/residential solar water heating programs.
			  • The 2011 IRP preferred portfolio includes 30 MW of solar water heating resources by 2020 (18 MW in the east side and 12 MW in the west side).
			• In the context of the Oregon solar RFPs, analyze the trade-offs between early and later acquisition of solar resources.
			<u>Combined Heat & Power (CHP)</u>
			• Pursue opportunities for acquiring biomass CHP resources, primarily tbrough the PURPA Qualifying Facility contracting process.
			  • 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)
			<u>Energy Storage</u>
			• 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 on incremental capacity value and ancillary service benefits of energy storage.
			• Conduct a study of grid flexibility for accommodating variable energy resources (VER) as part of the next IRP filing. The study will include the following elements:
			  – Definition of and suggest metrics by which to measure flexibility (applicable to all flexibility resources including: thermal, demand response (DR), and storage).
			  – An inventory of existing flexibility needs and the adequacy or capability of existing assets to meet them.
			  – A projection of flexibility needs in the IRP timeframe to successfully integrate project VER additions.
			  – A comparison of benefits and costs of obtaining flexibility from the range of flexibility resources (conventional thermal, DR, storage, etc).
			<u>Renewable Portfolio Standard Compliance</u>
			• Develop and refine strategies for renewable portfolio standard compliance in California and Washington.
			• PacifiCorp will expand the next IRP to include discussion of RPS compliance strategies and the role of REC sales and purchases. The Company will be selective in its discussion to avoid conflict between the IRP, RPS Implementation Plan and RPS Compliance Report.

2	**Intermediate / Base-load Thermal Supply-side Resources**		• 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. • 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. The reexamination will

ORDER NO. 12 082

APPENDIX A
PAGE 3 OF 8

Action Item	Category		Action(s)
			include documentation of capital cost and operating cost tradeoffs between resource types. • 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. • Issue an all-source RFP in early 2012 for potential acquisition of peaking/intermediate/baseload resources by the summer of 2016 to fill any remaining resource need indicated by an updated load and resource balance reflecting the results of DSM RFPs, acquisition of front and other relevant information.
3	**Firm Market Purchases**		• Acquire economic front office transactions or power purchase agreements as needed through summer2016. – 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. – Actively search for market options that could cost-effectively defer acquisition or construction of a 2016 CCCT resource.
4	**Plant Efficiency Improvements**		• 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. – 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.[2] • Continue to monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules. • For the next IRP complete a study of cost-effective and reliable production efficiency opportunities at generating facilities (station load reduction opportunities not currently being captured in the IRP) where the Company has sole ownership of the facility. The resource opportunities identified will be modeled against competing demand and supply-side resources in the next IRP. Those selected will be targeted for completion by 2015 provided plant outages are not required.

[2] *PacifiCorp Energy Heat Rate Improvement Plan*, April 2010.

ORDER NO. 12 082

APPENDIX A
PAGE 4 OF 8

Action Item	Category		Action(s)
5	Class 1 DSM		Acquire at least 140 MW of incremental cost-effective demand-side management resource by 2013 and up to 250 MW by 2015. – Finalize an agreement for the commercial curtailment product (which includes customer-owned standby generation opportunities). If cost effective, the company will file for approval by the 3rd quarter of 2012. – Complete an analysis of the economic feasibility of Class 1 irrigation load control in the west by the second quarter of 2012. If the analysis suggests Class 1 irrigation load control is economic in the west, the Company will source delivery of a program through a Request for Proposal concurrent with the re-sourcing of Class 1 irrigation load control program delivery in the east by the third quarter of 2012. – Issue an RFP in 2012 to re-procure the delivery of the Cool Keeper program following the 2013 control season. For the RFP, the Company will seek market approaches acceptable to Utah regulators to expand the program beyond its current level beginning in 2014.
6	Class 2 DSM		• 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. • Acquire at least 900 MW[3]and up to 1,800 MW of cost-effective Class 2 programs by 2020, equivalent to at least 4,533 GWh and up to 9, 2 DSM by 2016. – By 1st quarter of 2012 file a residential home residential home comparison report program in Utah and Washington, and investigate broader applications by the end of 2014 that can be implemented by 2016. – By 3rd quarter 2012 the Company will submit for commission approval a plan to acquire energy efficiency resources from the Company's Special Contract customers in Utah and Idaho that can be reliably verified and delivered by 2016, those states approve a cost-recovery mechanism for the plan. – By 1st quarter 2012 issue a system-wide RFP (excluding Oregon) for specific direct install and other direct distribution programs targeting savings from the residential and small commercial sectors that can be delivered beginning in 2013._The Company will seek to acquire all cost-effective resources that are available from the RFP. The cost effectiveness analysis will consider any adverse impact on the existing DSM programs. The results of the RFP will be known prior to the Company seeking acknowledgement of the final short list for the all-source RFP. The Company will promptly file for commission approvals to implement the cost-effective programs. • For the next IRP, prior to beginning modeling and screening of DSM, and as part of the public input process, provide an analysis of alternatives to the current supply curve bundling and ramping methods for modeling

[3] Adjusted to reflect 2011 IRP's initial MW contribution from Class 2 resources expected to be acquired in Oregon (reduces the MW contribution from Oregon from 562 MWs by 2020 to 283 MWs, a 279 MW reduct

ORDER NO. 12 082

APPENDIX A
PAGE 5 OF 8

Action Item	Category		Action(s)
			energy efficiency measures. • By the end of 2012 provide an analysis of the sufficiency of current staffing levels to achieve programmatic cost effective energy efficiency targets established in this plan. • 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 provided the Company receives approval by the appropriate Commission for recovery of the study cost through the demand-side customer efficiency surcharge.. (The Washington distribution energy efficiency study final report was completed December 26, 2011.) – Include in the 2013 IRP a detailed plan and schedule to implement cost-effective CVR in each state as approved by the state. – By May 1, 2012 the company will schedule a work shop in each of its major states with commission staff to present findings of the Washington CVR evaluation. – By the end of 2012 perform a high-level screening of 40 percent of its distribution circuits in each of the states to identify circuits where cost effective energy savings appears viable and detailed circuit study is warranted provided the Company receives approval by the appropriate Commission for recovery of the study cost through the demand-side customer efficiency surcharge. – By the end of 2013 perform a high-level screening of the remaining 60 percent of its distribution circuits in each of the states to identify circuits where cost-effective energy savings appear viable and detailed circuit study is warranted provided the Company receives approval by the appropriate state commission for recovery of the study cost through the demand-side customer efficiency surcharge. – In the 2013 IRP include the results of the CVR evaluation to date.
7	**Class 3 DSM**		• During 2012 update the Conservation Potential Assessment to more accurately reflect Class 1 and 3 DSM resource opportunities in regards to 1) market and regulatory capabilities and climates in each state, 2) interactions within and between Class 1 and Class 3 resource potentials identified, and 3) the impact of existing Class 3 programs on product potential. • During 2012 have a third-party consultant review and prepare a report on how other utilities treat price-responsive products in their resource planning process (for example, as an adjustment to their load forecast and/or as a firm planning resource), and prepare a recommendation on how the Company might apply contributions from price products to help defer investments in other resource options cost-effectively. • For the 2013 IRP provide a sensitivity analysis, similar to portfolio development Case 31 in the 2011 IRP, that more accurately reflects incremental Class 3 product opportunities (incremental to Class 1 products, other Class 3 products, and to existing impacts of Class 3 products the Company is already running). • Implement in Utah and Washington (subject to regulatory approvals) residential information pilots to test the effects of providing customers greater amounts of usage information on the quantity of electricity they consume. The pilots will leverage the existing AMR metering currently available in these states. – Pilots will consist of three test groups each receiving varying levels of usage information:

ORDER NO. 12 082

APPENDIX A
PAGE 6 OF 8

Action Item	Category		Action(s)
			o Group 1 - Home comparison reports and energy conservation suggestions o Group 2 - Daily usage data through Home Energy Monitoring software (key component to pricing products) o Group 3 – Home comparison reports, energy savings suggestions, and daily usage data through Home Energy Monitoring software Pilots will be implemented in 2012, run throughout 2013, and an analysis and recommendation prepared in 2014, prior to the development of the 2015 IRP. • If the analysis of Class 1 irrigation load control in the west (see action item 5) indicates that such programs are non-economic, investigate, through a pilot program in Oregon a Class 3 irrigation time-of-use program as an alternative approach for managing irrigation loads in the west.
8	**Planning and Modeling Process Improvements**		• Incorporate plug-in electric vehicles and Smart Grid technologies as a discussion topic for the next IRP. •
9	**Coal**		• The Company will host a technical workshop for stakeholders and the commissioners on February 17, 2012 for stakeholders that have a confidentiality agreement in place. – At the technical workshop, the Company will review with stakeholders the methodology, assumptions and recently completed analysis of upcoming Naughton 3 emission control investments. The Naughton 3 analysis will be provided to stakeholders, subject to confidentiality agreements, as soon as practicable. – At the technical workshop, the Company will present the methodology, assumptions and results of a Coal Replacement Study screening analysis performed for Jim Bridger 3, Jim Bridger 4, Hunter 1 at a minimum. The Company will complete the analysis on as many other units as possible within the time constraints. The Company will also present information pertaining to planned investments in the Craig and Hayden facilities of which the Company has ownership share but does not have operational responsibilities. – The screening analysis will be performed using a spreadsheet model that assumes a gas-fired CCCT, scaled to the size of the coal unit being analyzed, replaces the coal unit in 2015. – The screening analysis will include line-item results showing annual capital costs and fixed and variable operating costs for each coal unit and the replacement CCCT resource. – The screening analysis will be performed on three different market scenarios pairing varying levels of natural gas prices and CO2 costs. At least one scenario will include a low gas/high CO_2 pairing. – The screening analysis will report a rank order of the nominal levelized net present value revenue requirement (PVRR) benefit/cost on a per kW-mo basis for each scenario. – The Company will make available to stakeholders that have signed appropriate confidentiality agreements the assumptions and results of the screening Study five business days before the technical workshop.

ORDER NO. 12 082

APPENDIX A
PAGE 7 OF 8

Action Item	Category		Action(s)
			• The Company will include in its 2011 IRP update an updated Coal Replacement Study focusing on those units analyzed in the screening analysis as described above. – The updated Coal Replacement Study will be performed using the System Optimizer model and will explore a range of natural gas prices and CO2 costs in varying combinations. – The updated Coal Replacement Study will discuss and evaluate flexibility in the emerging environmental regulations and the associated economics that may present options to the Company to avoid early compliance costs by offering to shut down certain individual units prior to the end of their currently approved depreciable lives. – In the updated Study, the Company will provide a concise explanation and transparent example of its treatment of post-2030 costs and will provide an analysis that shows the results of treatments of environmental investments made prior to 2015 both avoidable and unavoidable. • *The Company recognizes that Commission acknowledgement of this action item does not impact Commission disposition of environmental investments by the Company.*
10	**Transmission**		• In the scenario definition phase of the IRP process, the Company will address with stakeholders the inclusion of any transmission projects on a case-by-case basis. – Develop an evaluation process and criteria for evaluating transmission additions. – Review with stakeholders which transmission projects sbould be included and why. – Based on the outcome of these steps, PacifiCorp will provide appropriate transmission segment analysis for which the Company requests acknowledgement (including Wallula to McNary and Sigurd to Red Butte).
11	**Planning Reserve Margin**		• For the 2011 IRP update include the results of a System Optimizer portfolio sensitivity analysis comparing the resource and cost impacts of a 12 percent versus 13 percent planning reserve margin.

ORDER NO. 12 082

APPENDIX A
PAGE 8 OF 8