Table 14. Wind integration cost comparison to the 2008 IRP.

Study	2008 IRP	2010 Wind Integration Study	2010 Wind Integration Study
Wind Capacity Penetration	2734 MW	1372 MW	1833 MW
Tenor of Cost	20-Year Levelized	3-Year Levelized	3-Year Levelized
Expected to Day Ahead ($/MWh)	$0.28	-	-
Day Ahead to Hour Ahead ($/MWh)	$2.17	-	-
System Balancing ($/MWh)	-	$0.82	$0.86
Subtotal Interhour / System Balancing	$2.45	$0.82	$0.86
Intra Hour Reserves[1] ($/MWh)	$7.51		
2010 Study Operating Reserves ($/MWh)		$8.03	$8.85
Total Wind Integration	**$9.96**	**$8.85**	**$9.70**
Assumptions			
Forward Price Curve	Oct 2008, $8CO2	Mar 2010, No CO2	Mar 2010, No CO2

1 - IRP resources were available to meet Operating Reserve demand before the in-service year, which lowers wind integration cost

4.3 Application of Wind Integration Costs in the 2011 Integrated Resource Plan

The start of portfolio development for PacifiCorp's 2011 IRP is scheduled for September 2010. Portfolio development relies on the Company's capacity expansion optimization model, called System Optimizer. (Note that wind integration impacts are treated as an increased resource cost in the System Optimizer model.) The high-end wind capacity penetration scenario will not be completed until after portfolio development is well underway. Until costs are assessed for the high-end wind capacity penetration scenario, PacifiCorp will use the costs developed for the 1,833 MW penetrations scenario, totaling $9.70/MWh of wind generated power.

Appendix A

Simulation of Wind Generation Data

A.1 Detailed Discussion of Statistical Patterns of the Historical Wind Output Data

From the available ten-minute interval historical wind generation data over the 2007 to 2009 Initial Term, there are four key observations. First, wind output has a seasonal pattern. Taking one plant as an example, Figure 1A shows capacity factor data for Leaning Juniper in 2009. The red markers in the figure indicate the median of the distribution, and the wide bar delineates the 25th to 75th percentiles of the distribution. Figure 1A shows the median, as well as the range of observed capacity factors in each month in 2009 for Leaning Juniper varies significantly. Second, the monthly standard deviations for capacity factor output are very different across sites in most months. Figure 2A compares the output patterns across June, July, and August of 2009 for Leaning Juniper and Combine Hills and shows that non-normality is evident in the data. Again, the red markers indicate the median of the distribution, and the wide bar represents the 25th to 75th percentiles in the distribution. Third, the commonly-accepted notion that wind output follows a pronounced diurnal pattern is only partially supported by the various historical profiles in the dataset, as apparent in Figure 3A. In general, such recurring patterns are more easily found in average aggregate representations of the data on hourly level, rather than by examining higher resolution ten-minute data.

Figure 1A. Leaning Juniper 2009 monthly capacity factors.

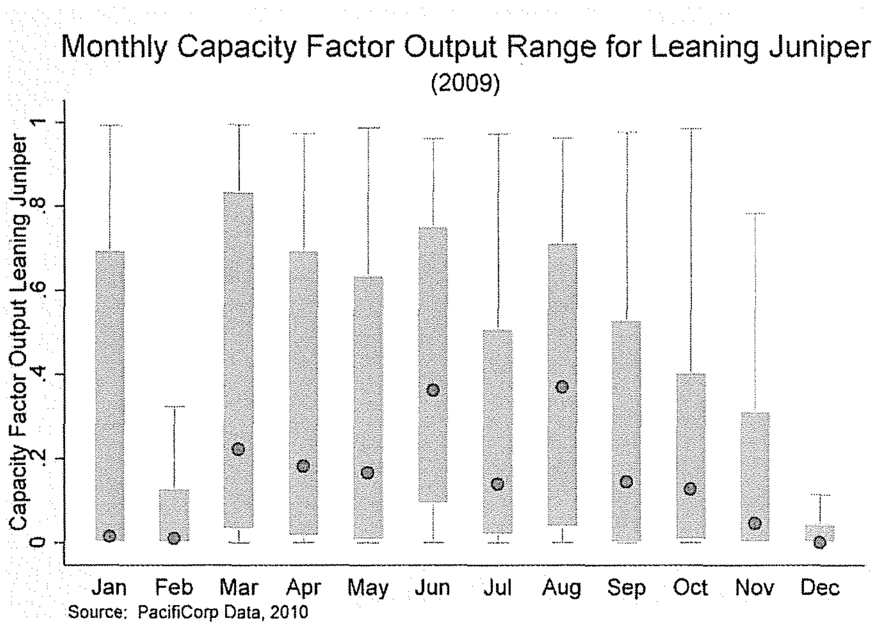


Figure 2A. Comparison of Leaning Juniper and Combine Hills capacity factors.

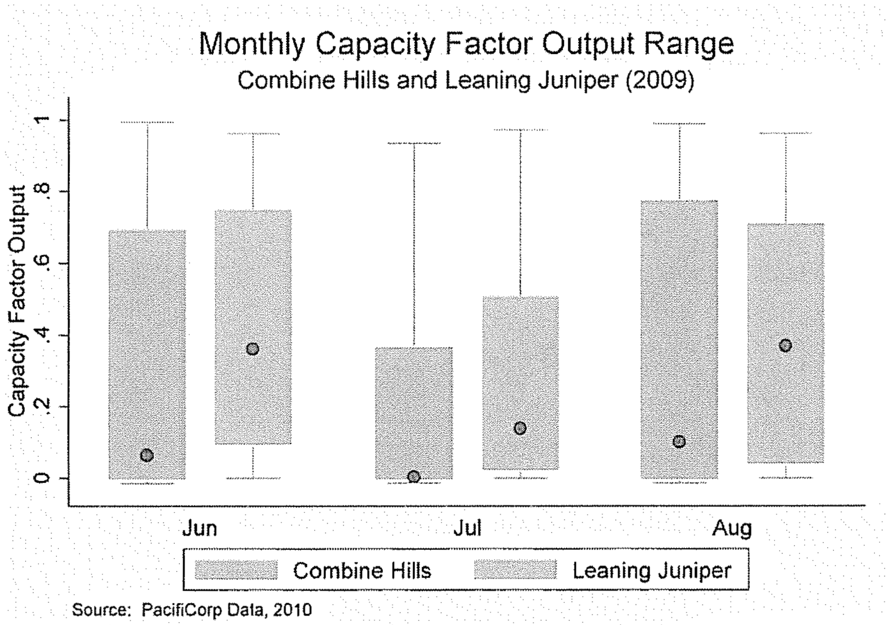
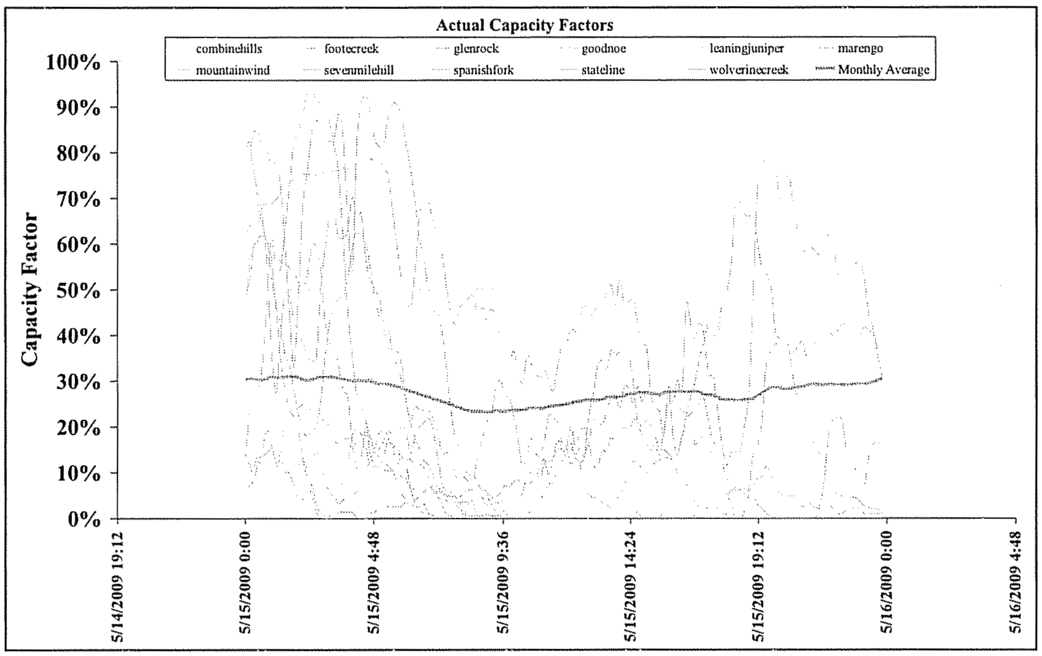


Figure 3A. Daily generation patterns of several PacifiCorp wind plants.



Finally, Figures 4A and 5A present the empirical distribution of the 2009 capacity factor output of Leaning Juniper and Combine Hills, respectively. Both plants' hourly capacity factor data represent two key patterns to the study. One, that there are a very substantial number of zero generation hours for each station. Two, the output varies greatly through the potential capacity range of each generating station, implying the wind generation will have the characteristic to vary from one time period to the next. This is different behavior than would be implied by a strong bimodal diurnal pattern, which would imply very regular on/off behavior with and without wind.

Figure 4A. Distribution of observed 2009 hourly capacity factors at Leaning Juniper.

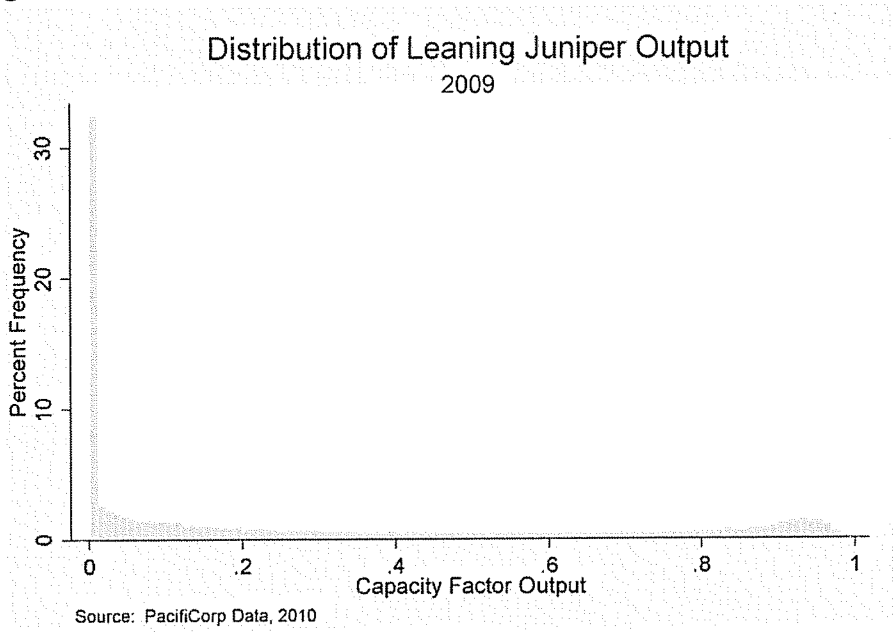
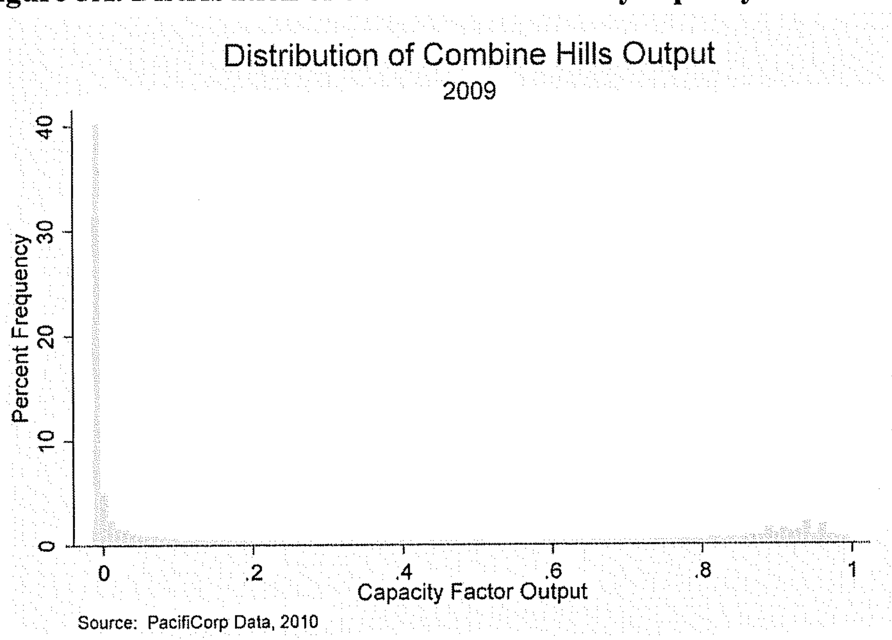


Figure 5A. Distribution of observed 2009 hourly capacity factors at Combine Hills.



A.2 Time Pattern of the Historical Wind Data

The time-series properties of the wind generation data are also important to the Study. Initial data analysis revealed that the wind generation profiles in the dataset were consistently characterized by a slowly decaying auto correlation process, while their partial autocorrelations are significant up to 6 period lags. In other words, the wind data in a ten-minute period is heavily consistent with the previous 10-minute interval and, therefore, over time, the wind pattern could be described as influenced by its behavior in the previous time periods. Partial correlation measures the autocorrelation at a specific lagged time frame, while controlling for the effect of preceding lags. Partial autocorrelation is useful in determining the number of lagged terms to include as explanatory variables in a regression model. Figures 6A through 9A show the full and partial auto correlation factors for the Leaning Juniper and Combine Hills wind plants. Figures 6A and 7A show that the predictive power fades regularly over time lag. Figures 8A and 9A show that the oscillating nature of wind generation is more apparent in the negative predictive power of the 2nd and 4th lags.

Figure 6A. Autocorrelation coefficients for successive ten minute lags in capacity factor for Leaning Juniper.

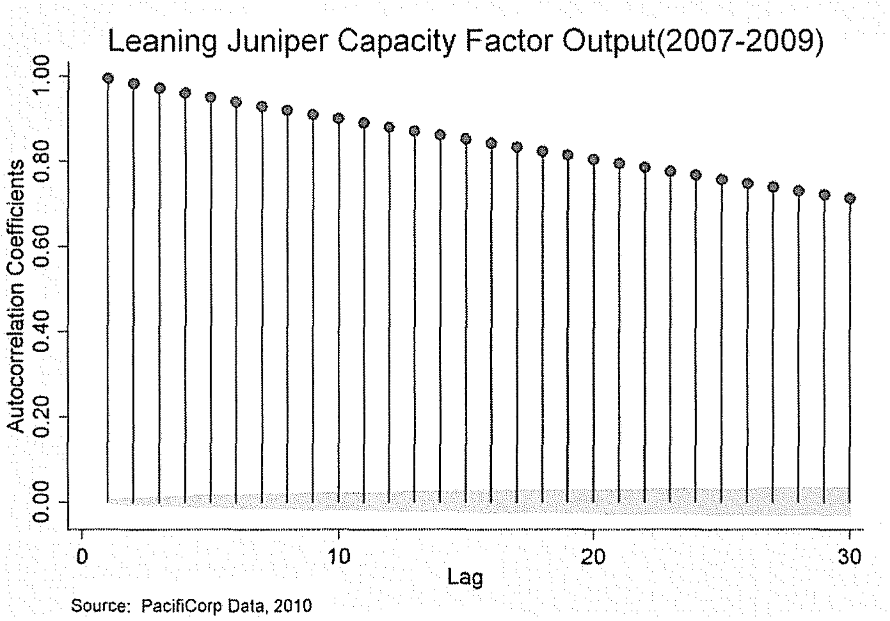


Figure 7A. Autocorrelation coefficients for successive ten minute lags in capacity factor for Combine Hills.

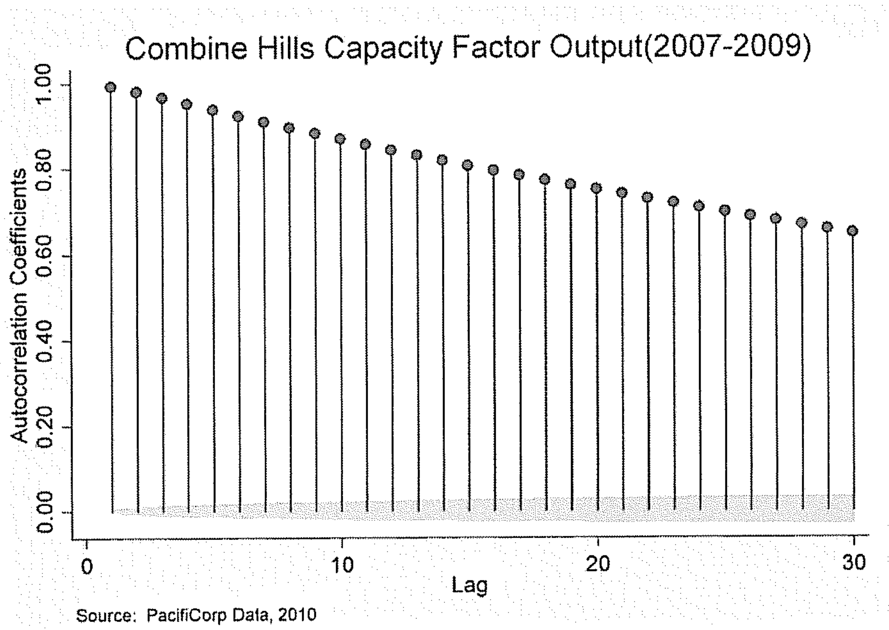


Figure 8A. Partial autocorrelation coefficients for lags in capacity factor for Leaning Juniper.

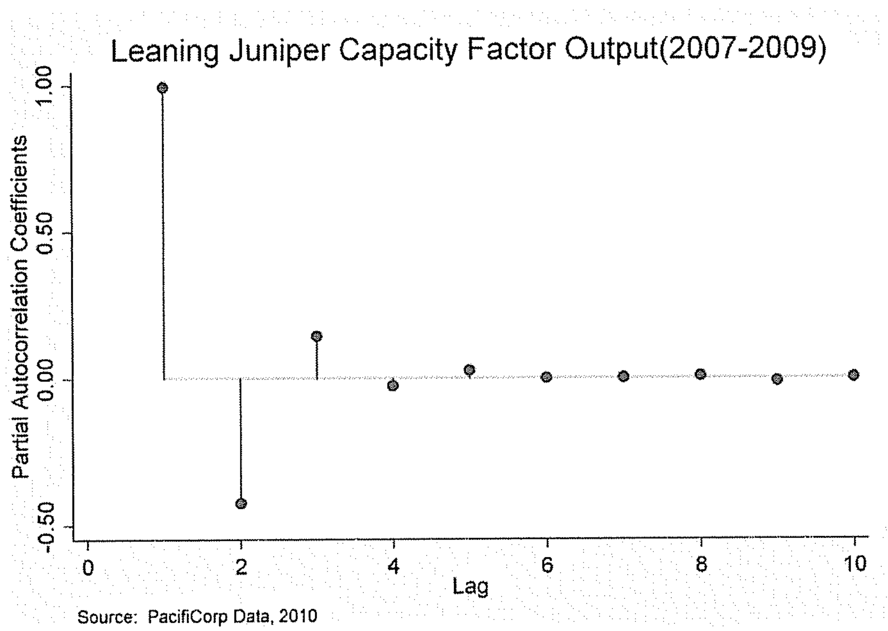
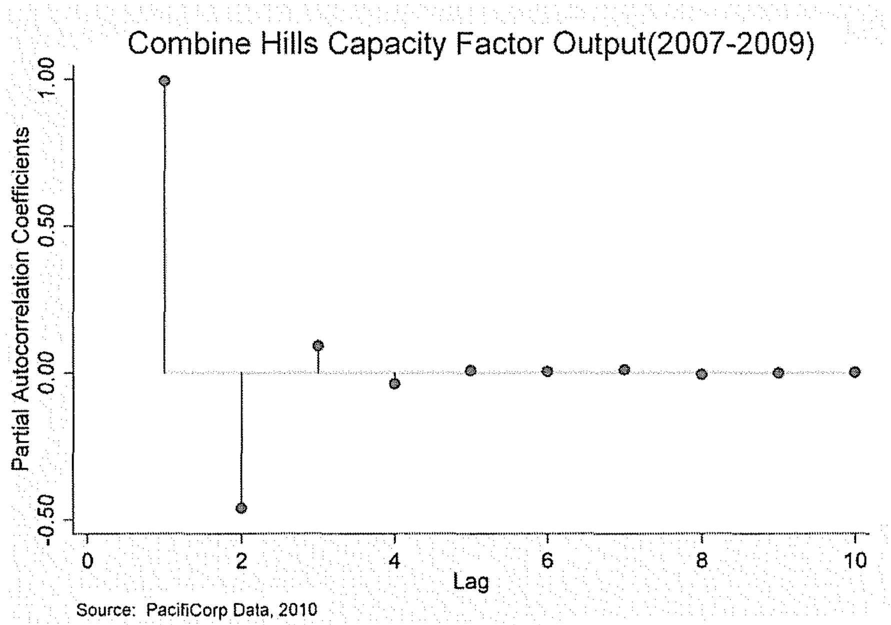


Figure 9A. Partial autocorrelation coefficients for lags in capacity factor for Combine Hills.



A.3 Data Clean-up and Verification

The source wind generation data were characterized by a number of issues that needed data clean-up, verification and, in some cases, adjustments. The first observed issue is that for certain records over various periods of time, the historical wind output data were zero. Those observations covered varying lengths of time and, in some instances, up to a few months. However, we noticed that the zero-value data blocks consistently occurred only at the beginning of a wind project's chronological energy output data and therefore it is suspected that those were probably periods when the plant had not yet been fully commissioned. Thus, those observations are treated as "missing" and excluded them from the historical data set.

Next, through our source data review, we identified that the output of certain plants seemed to have much smaller capacity factors and increased over time. This trend seemed to have extended beyond the natural volatility of wind generation for those wind sites and showed up as a gradual increase over time and reaching a maximum after a number of months. This observation seemed to suggest that the historical data were capturing the build-out of a wind site before it has reached its commercial operation date. As the maximum available capability through wind plant construction on a daily basis was not documented, the decision was made to exclude wind output data for dates prior to the known commercial operation date for each wind site. As a result, the data set used for simulations was limited to include only date ranges that conform to the known commercial operation dates shown in Table 1A.

Table 1A. Summary of wind plant start dates and nameplate capacity.

Plant name	Applied Commercial Operation Date	Nominal Capacity (MW)	Observed Max Output (MW)
Dunlap I	11/1/2010	111	Data Unavailable
Goodnoe Hills	5/31/2008	94	95
Glenrock	1/17/2009	237	232
Glenrock III			
Rolling Hills			
High Plains	9/13/2009	99	148
McFadden Ridge I	10/10/2009	29	29
Leaning Juniper	9/14/2006	101	103
Marengo I	6/26/2008	211	206
Marengo II			
Seven Mile Hill I	12/31/2008	119	123
Seven Mile Hill II			
Combine Hills	6/17/2003	41	41
Wolverine Creek	4/29/2005	65	65
Mountain Wind I	9/29/2008	141	137
Mountain Wind II			
Three Buttes	12/1/2009	99	Data Unavailable
Top of the World	12/31/2010	202	Data Unavailable
Spanish Fork	7/31/2008	19	22
Foote Creek I	4/1/1999	95	137
Foote Creek II			
Foote Creek III			
Foote Creek IV			
Rock River			

The sites that were affected by these revisions were:

- Goodnoe Hills (observations were set to missing for November 2007 through May 2008),
- Marengo (observations were set to missing for February 2007 through May 2008),
- Spanish Fork (observations were set to missing for April 2008 through Jul 2008),
- Mountain Wind (observations were set to missing for April 2008 through September 2008),
- Seven Mile Hill (observation were set to missing for November 2008 through December 2008),
- McFadden Ridge (observations were set to missing for June 2009 through September 2009),
- High Plains (observations were set to missing for February 2009 through August 2009),
- Glenrock (observations were set to missing for November 2008 through December 2008).

- That leaves five wind sites that were not affected by this adjustment —Leaning Juniper, Combine Hills, Stateline, Wolverine Creek, and Foote Creek.

The second clean-up process involved understanding the aggregation of data and the interpretation of the plant size. The data provided to the technical advisor contained single wind output data stream for sites that share the same principal name but are distinguished as individual projects—those include Marengo and Marengo II, Mountain Wind and Mountain Wind II, Seven Mile Hill and Seven Mile Hill II, Glenrock and Glenrock III. The wind output data, which were collected on-site, did not distinguish between separate sharing the same name.

The third clean-up involved the fact that the maximum output levels observed in the wind output data sometimes exceed the capacity officially available to PacifiCorp. The Study team decided to use the maximum output found in each wind profile data stream to be the *de facto* wind site megawatt capacity. We used this capacity level and converted each 10-minute output into a capacity factor value ranging from 0 to 1.[28]

A.4 Wind Data Simulation Methodology

A.4.1 General Description

The overall methodology centered on using available data to estimate the missing data. To do so, the statistical relationships between pairs of sites were studied and those relationships were used to derive or estimate the wind output for periods that historical data are incomplete or missing. For example, if there was a *fully available* set of historical data for site A, but *partially missing* for site B, the overlapping periods during which historical data are available for both sites A and B were used to estimate the statistical relationship using that data. Then the technical advisor employed that statistical relationship and used the available data from site A for the period when site B has missing data to estimate wind data for that period. If site B has *completely missing* data, the technical advisor applied NREL's simulated data (from 2004-2007) to establish the statistical relationship between sites A and B and then applied that estimated relationship to the historical data of site A and again, estimated site B's wind output accordingly.

A.4.2 Wind Generation Estimation Model Specification

In general, the modeling approach is based on the use of contemporaneously available ten-minute wind capacity factor data from *fully available* wind profiles to simulate capacity factor data for profiles with *partially* or *completely missing* wind output. As prior figures demonstrated, ten-minute wind output exhibited a generally volatile profile with several notable features. First, output from previous periods is highly indicative of the current level of output, with the partial autocorrelations significant up to as many as six lags. Second, the diurnal patterns were harder to discern on a consistent basis. Given these characteristics and our preliminary analysis, we chose to include six lagged terms in addition to the concurrent wind output term in the model used to estimate the statistical relationship between pairs of sites. We have found that such

[28] The capacity factor represents the output at a given point in time as a fraction of the maximum possible output for the wind project. For example, a capacity factor of 0.23 indicates that current output is 23% of the total capacity of the wind site.

specification allows us to capture the time-based behavior and time-dependence of the wind data used in the Study. This approach also captures some of the spatial relationship between the two sites—as wind moves from one site to the other, its impact on the other site is delayed in time. The equation below describes the general structure of the model[29]:

$$Site_t^A = \alpha_0 Site_t^B + \alpha_1 Site_{t-1}^B + \alpha_2 Site_{t-2}^B + \alpha_3 Site_{t-3}^B + \alpha_4 Site_{t-4}^B + \alpha_5 Site_{t-5}^B + \alpha_6 Site_{t-6}^B + \varepsilon$$

A.4.3 Wind Generation Estimation Model for Constrained Output

An important challenge in specifying this model is the nature of the capacity factor variables. Capacity factor is used instead of absolute wind output levels to translate between small and large wind plants. By such a construction, the wind output measured in capacity factor terms can only take values between 0 and 1 (or, equivalently 0% and 100%). Attempting to predict a limited dependent variable using a standard linear ordinary least squares (OLS) approach resulted in estimated values for the dependent variable (or sites with *partially missing* and *completely missing* historical data) that are outside the possible value range.

For example, for given mean values of the explanatory variables, the linear OLS model might result in a predicted mean dependent variable value greater than a capacity factor of 100%. This is due to the fact that a linear OLS model does not limit the outcome range for the dependent variable. In the literature, a model whose dependent variable is limited at either one or both upper and lower ends of its range is called a "censored" model.[30] A standard approach for estimating a censored model is to use the *Tobit* regression model. The *Tobit* model was originally developed by James Tobin (1958)[31] and employs an estimation technique, which recognizes the limited ("censored") range of possible values that the *observed* dependent variable can take.[32] As a result, predicted mean values for the dependent variable will behave as expected and not exceed the natural capacity limits of 0 and 1, as specified in our case.

The *Tobit* model uses a maximum likelihood process, which takes into account the probability of obtaining an observation that lies inside the censoring interval. In other words, *Tobit* typically is used to estimate the likelihood of a value to be equal to some expected quantity. The model assumes that the true value of the dependent variable (y*) is explained by a number of independent variables, where the regression error term (epsilon) is normally distributed with a zero mean. In addition, if y* is between 0 and 1 we observe y*, however, if y*<0 we observe 0 and, similarly, if y*>1, we observe 1. The maximum likelihood estimation uses the probability of each individual observation being censored to estimate the regression coefficients.[33] In other words, the regression coefficients are determined to ensure that their value maximizes the likelihood of obtaining the observed values of y*.[34]

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[29] We specify a regression model that has no constant term.

[30] Greene, William H., "Econometric Analysis", 5th Ed., Prentice Hall 2003, p. 764.

[31] Gujarati, Damodar N., "Basic Econometrics", McGraw Hill 2003, p. 616; Kennedy, Peter "A Guide to Econometrics," 5th Ed., MIT Press 2003, pp. 289-290.

[32] Ibid.

[33] For example, see "STATA Base Reference Manual Release 11", Stata Corp. pp. 1939-1948; Maddala, G. S., "Limited-Dependent and Qualitative Variables in Econometrics.", Cambridge University Press 1986, pp.159-162.

[34] For more detailed description of the Tobit model, please see Maddala, G. S., "Limited-Dependent and Qualitative Variables in Econometrics", Cambridge University Press 1986, pp.159-162.

In contrast to linear OLS regression, the *Tobit* regression model does not report an R-squared metric, which typically indicates the explanatory power of the regression model specification (with high R-squared value indicating stronger explanatory power). In other words, in the linear OLS regression, the adjusted R-squared measures the proportion of variance of the dependent variable that has been explained by the independent (right-hand-side) variables. There are a range of so-called "Pseudo R-Squared" metrics that have been proposed in the literature for use with maximum likelihood models, such as the *Tobit* model. However, their interpretation is not equivalent to the R-Squared in OLS. This is because estimates derived using a *Tobit* model are calculated via an iterative process designed to maximize the likelihood of obtaining the observations of the dependent variable, rather than to minimize variance.[35]

The technical advisor used the statistical software package STATA© to perform the regressions using the Tobit model. The model specification uses the chosen explanatory variables and generates a censored prediction of y* where the relevant upper and lower censoring limits are taken into account.[36] An example of the six-lag model the technical advisor settled upon for significance is below:

$$\begin{aligned} Goodnoe_t^A &= \alpha_0 LeaningJuniper_t^B + \alpha_1 LeaningJuniper_{t-1}^B + \alpha_2 LeaningJuniper_{t-2}^B + \\ &+ \alpha_3 LeaningJuniper_{t-3}^B + \alpha_4 LeaningJuniper_{t-4}^B + \alpha_5 LeaningJuniper_{t-5}^B + \alpha_6 LeaningJuniper_{t-6}^B + \varepsilon \end{aligned}$$

A.4.4 Using NREL's Wind Data to Facilitate Wind Simulation for Sites without Historical Information

To simulate wind data of sites with no historical information, the technical advisor used the NREL wind data to estimate the statistical relationship between pairs of sites and then used the estimated relationship to simulate the necessary wind data. For sites with *completely missing* historical wind data, NREL sites are chosen to serve as a proxy wind profiles.

NREL's *Western Wind Dataset* was created by *3TIER* for use in NREL's *Western Wind and Solar Integration Study*. The dataset was synthesized using numerical weather prediction (NWP) models "to recreate the historical weather for the western U.S. for 2004, 2005, and 2006. The modeled data were temporally sampled every 10 minutes and spatially sampled every arc-minute (approximately 2 kilometers)."[37] We refer to this wind data set as the "NREL data".

The first step in using the NREL *Western Wind Dataset* is to identify NREL-modeled sites that are the closest in geographical terms to the relevant PacifiCorp wind sites. These are called the "NREL proxies" for each corresponding PacifiCorp wind site. The technical advisor then estimated the statistical relationship between the pairs of NREL proxies (that correspond to PacifiCorp wind sites) and used the statistical relationship to carry out the rest of the simulation

[35] For more information, please see: Long, J. Scott. "Regression Models for Categorical and Limited Dependent Variables" Thousand Oaks: Sage Publications, 1997; Freese, Jeremy and J. Scott Long. "Regression Models for Categorical Dependent Variables Using Stata", College Station: Stata Press, 2006.
[36] For more information, please see: Baum, Christopher F., "An Introduction to Modern Econometrics Using Stata", College Station: Stata Press, 2006, p. 264.
[37] http://www.nrel.gov/wind/integrationdatasets/western/methodology.html#methodology [accessed July 1, 2010]

described above. PacifiCorp staff provided the technical advisor with the geographical coordinates (latitude and longitude) for the PacifiCorp wind sites as summarized in Table 2A. In addition, the NREL data contains comprehensive information on the geographical coordinates of all modeled sites.[38] The technical advisor then determined the closest NREL proxy for each of plant.[39]

Table 2A. NREL Proxies selected for pertinent PacifiCorp plants.

PacifiCorp Plant Name	Closest NREL Site ID	Distance (km)
High Plains	16676	0.5
McFadden	16676	0.5
Rock River	31422	0.4
Rolling Hills	23909	2.9
Dunlap	19280	0.8
Three Buttes	23870	5.3
Top of the World	23803	4.8

Table 2A shows each PacifiCorp-NREL pair and the calculated distance between them. We should note that High Plains and McFadden Ridge share the same geographical location and, as a result, are paired with the same NREL-modeled site. As a result, High Plains and McFadden Ridge have identical simulated profiles. (This is a function of the study's approach of simulating wind generation output based on geographical location rather than wind project name—for example, the same simulated profile is also used to represent the Mountain Wind/Mountain Wind II pair of wind sites.)

After determining the set of NREL sites to be used in the simulation analysis, NREL data were formatted, compiled by site, and labeled using their PacifiCorp counterpart's name. Similar to the earlier approach in formatting the PacifiCorp data, NREL wind output data were converted into capacity factor terms (using a 30 MW capacity value for each site as specified in the NREL description of the dataset).[40]

[38] The main web portal for the NREL Western Wind Dataset can be accessed at http://wind.nrel.gov/Web_nrel

[39] Geographical coordinates for two points on the earth's surface can be converted to a straight-line distance using a range of alternative algorithms, which take into consideration the shape of the earth and use trigonometric formulas to project and measure surface distances. For the purposes of this study, the Spherical Law of Cosines was used to calculate the distance between each relevant PacifiCorp wind site and every site in the Western Wind Dataset. Fore more information, please see: Weisstein, Eric W. "Spherical Trigonometry." From MathWorld -- A Wolfram Web Resource. http://mathworld.wolfram.com/SphericalTrigonometry.html [accessed July 1, 2010]

Distance (km) = ArcCos(Sin(Latitude Pacificorp) * Sin(Latitude NREL) + Cos(Latitude Pacificorp) * Cos(Latitude NREL) * Cos(Longitude NREL - Longitude Pacificorp)) * 6371 km

[40] http://www.nrel.gov/wind/integrationdatasets/about.html [accessed July 1, 2010]

A.4.5 Pairing of Wind Profiles Used for Regression

Recognizing the monthly seasonality of wind data, each modeled pair required twelve separate regression models per year, one for each month.[41] To ensure the use of observed historical wind data is meaningful, we require that a full year of overlap between a *fully available* wind profile and a *partially missing* wind profile. This means that if the *partially missing* wind profile only had 11 months of historical data, it was treated as a *completely missing* dataset and used the NREL data to help simulate the data from the period without historical data. To simplify the rest of this explanation, the *fully available* wind profile was a *predictor* and a site with *partially missing or completely missing* wind profile was a *predicted* site (because the process effectively used the available profile to "predict" the missing profile).

The Study focused on two methods in estimating monthly regressions. First, for sites with *partially missing* historical wind data that have at least 12 months of historical data, the data from a *fully available* site was employed as the *predictor* (such as Foote Creek, Combine Hills, or Leaning Juniper) to estimate monthly coefficients. From the coefficients derived in the regression estimation, the Study estimated the wind data for all the missing months. Second, for sites with *partially missing* data (and with less than 12 months historical data available) and sites with *completely missing* data, the NREL *closest neighbor* set of wind profiles was employed. The process estimated monthly regression models between the closest NREL site to the *predictor* and the closest NREL site to the *predicted*. Then the coefficients estimated in those regressions were applied to the PacifiCorp *fully available predictor* data to simulate 10-minute output data for the *predicted.* This second approach implicitly assumed that the monthly relationships between the *predictor* and the *predicted* derived from the 2004-2006 period (using available NREL data) were applicable to the Initial Term as represented by the PacifiCorp data.
Below in Figure 10A, a flow chart depicts the steps described above. Table 3A depicts the pairs of wind sites with left column containing the *predictor* and the right column containing the *predicted.*

[41] For example, if overlapping data for the *predictor* and the *predicted* are available for all of 2008 and 2009, we estimate a regression for January using data for that month from both 2008 and 2009. Then, the estimated coefficients from the regression will be used to predict the output for January of 2007 using the *predictor* 2007 data for that month.

Figure 10A. Wind generation data development flow chart.

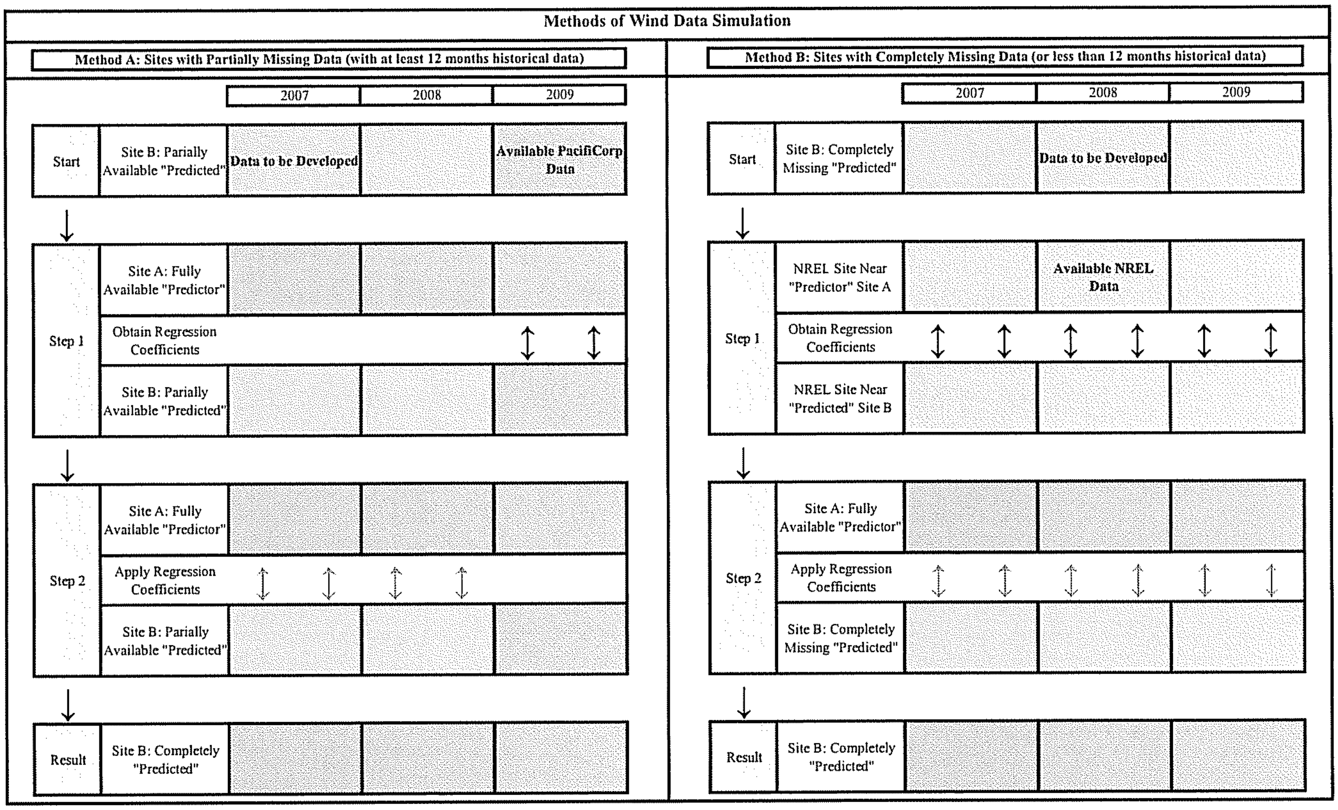


Table 3A. Pairs of wind projects used in data simulation.

Predicted	Predictor	Data Used
High Plains	Foote Creek	NREL/PacifiCorp
McFadden	Foote Creek	NREL/PacifiCorp
Rock River	Foote Creek	NREL/PacifiCorp
Rolling Hills	Foote Creek	NREL/PacifiCorp
Dunlap	Foote Creek	NREL/PacifiCorp
Three Buttes	Foote Creek	NREL/PacifiCorp
Top of the World	Foote Creek	NREL/PacifiCorp
Goodnoe	Leaning Juniper	PacifiCorp
Marengo	Combine Hills	PacifiCorp
Mountain Wind	Foote Creek	PacifiCorp
Seven Mile Hill	Foote Creek	PacifiCorp
Spanish Fork	Foote Creek	PacifiCorp
Glenrock	Foote Creek	PacifiCorp

A.4.6 Regression Analysis

The estimation process of the *Tobit* regressions was identical across all sites—the six-lag model is applied to a *predictor-predicted* pair. After estimation, the resulting coefficients were used to generate data for the *predicted* profile for all missing time periods using the values of the *predictor* in those time periods.[42] A sample of resulting regression coefficients for one month for one pair of wind sites is shown in Table 4A below.

Table 4A. Predictive capacity factor coefficients for the simulation of Goodnoe Hills wind generation using Leaning Juniper actual generation data.

Explanatory Variables	Estimated Coefficients
Capacity Factor Leaning Juniper	0.841***
	(0.0744)
Capacity Factor Leaning Juniper [t-1]	-0.321**
	(0.130)
Capacity Factor Leaning Juniper [t-2]	0.0314
	(0.135)
Capacity Factor Leaning Juniper [t-3]	0.0631
	(0.135)
Capacity Factor Leaning Juniper [t-4]	0.0597
	(0.135)
Capacity Factor Leaning Juniper [t-5]	0.00342
	(0.130)
Capacity Factor Leaning Juniper [t-6]	0.267***
	(0.0744)
Observations	4,464

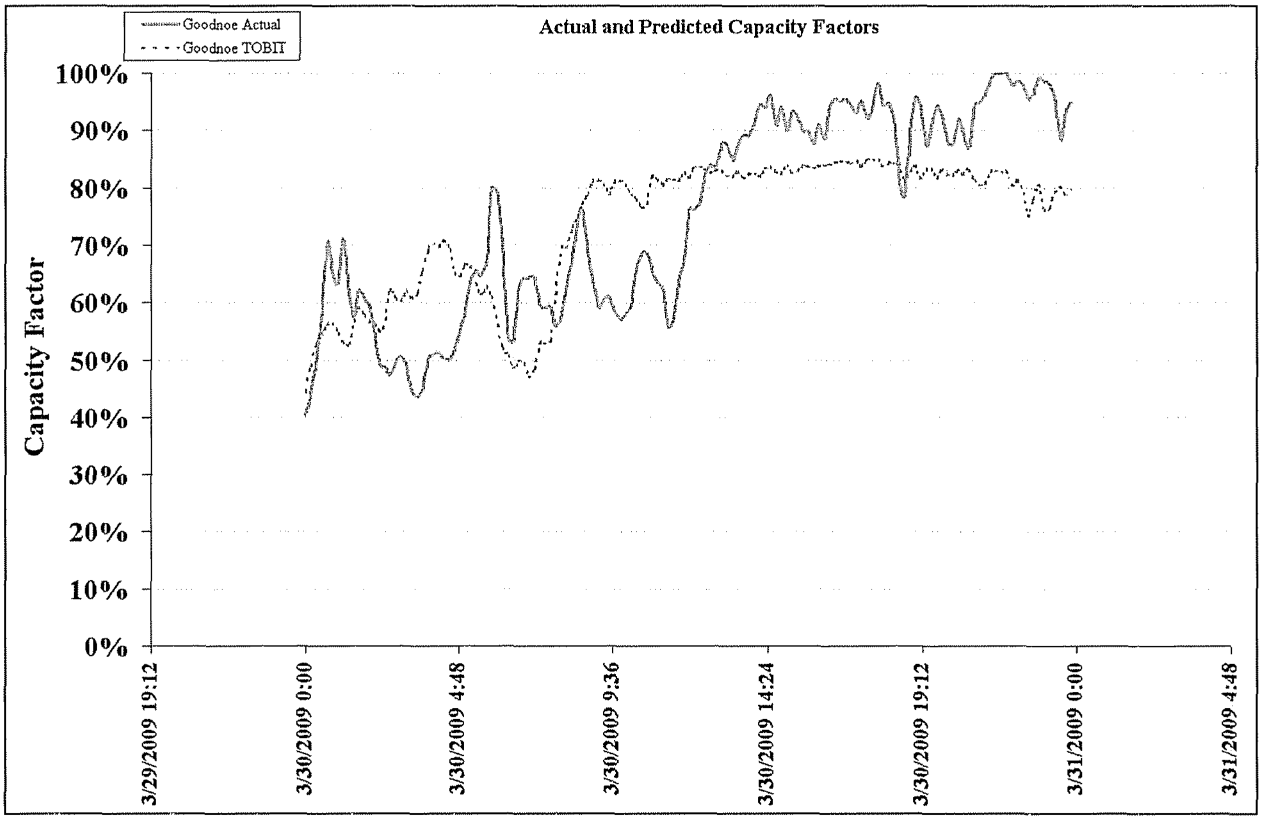
Note: Standard errors in parentheses.
*** $p<0.01$, ** $p<0.05$, * $p<0.1$

A.4.7 Estimate Mean Values of the Predicted

In general, using the estimated regression coefficients to derive a prediction for the dependent variable is done by using the mean values of the explanatory variables to arrive at the predicted mean value of the dependent variable. In this case, however, we are interested in generating predicted values of the dependent variable (*predicted)* for all individually observed values of the independent variable (*predictor*). As a result, applying the estimated regression coefficients to each individual observation of the explanatory variables will result in predicted values of the *predicted* that are significantly less variable than the true unobserved *predicted* series. This is due to the fact that the regression model assumes that the regression error is zero on average across the observations, but not in every individual instance. An illustrative comparison of the predicted mean value to the historical actual of the same period is shown in Figure 11A.

[42] Again, all estimation procedures and simulations were conducted using the commercially-available statistical software package STATA© (http://www.stata.com)

Figure 11A. Comparison of actual Goodnoe Hills capacity factors with predicted mean Goodnoe Hills capacity factors derived off of Leaning Juniper generation data.



A.4.8 Calculating the Regression Residuals

To address the loss of variability by simply using the regression coefficients in the estimation, the technical advisor subtracted the predicted values of the dependent variable from their corresponding observed values over the overlapping subset of *predicted/predictor* data used for the regression estimation.[43] This produced a set of regression residuals, which represent the amount by which predicted values for the known (historical) part of the data set were different from the actual observed values of the *predicted*.

Then, each regression residual value was categorized according to the level of predicted output it was originally associated with. The predicted values are then grouped in bins of 10 percentage points to create 10 bins that cover the range of 0% to 100% capacity factor output. For example, all residuals that were associated with a predicted output between 10% and 20% are grouped together. As Figures 12A and 13A show, the distributions of those residuals vary across bins.

[43] In the case of the PacifiCorp sourced data, this is done over the monthly regression data. For the Hybrid approach where NREL data was required, this is done with the NREL data.

Figure 12A. Highly non-normal residuals from bin 5 of the March regression of Goodnoe Hills capacity factor derived from observed Leaning Juniper data.

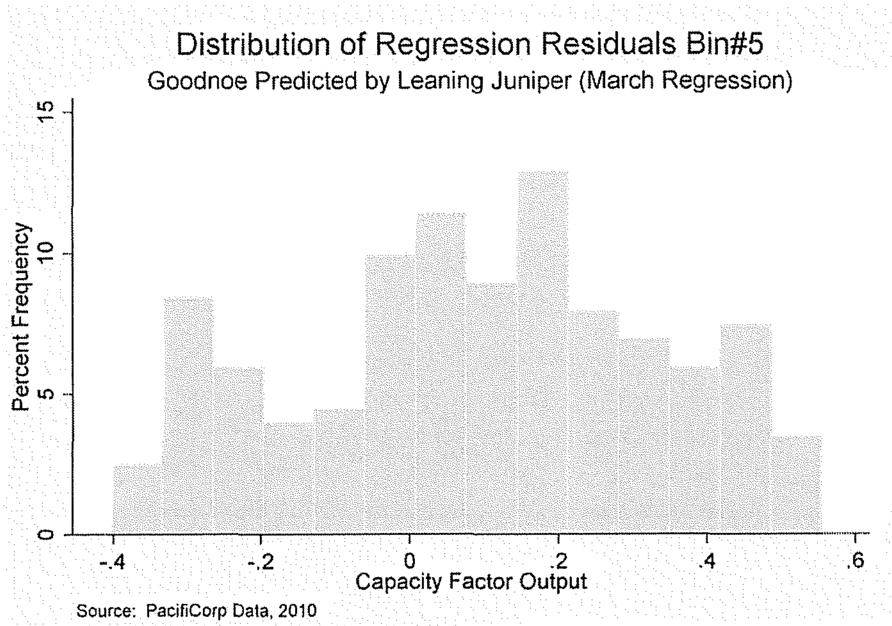
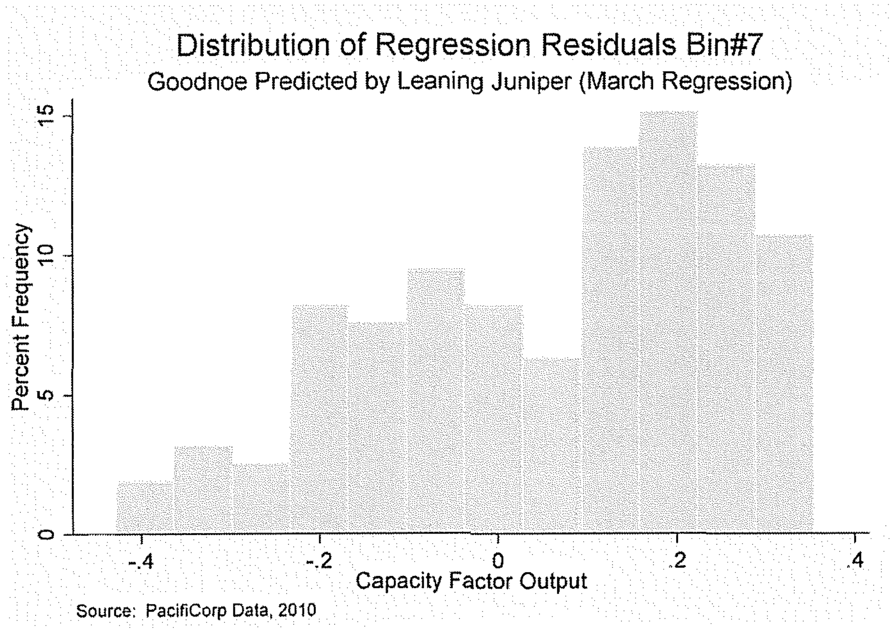


Figure 13A. Highly non-normal residuals from bin 7 of the March regression of Goodnoe Hills capacity factor derived from observed Leaning Juniper data.



A.4.9 Sample of Residuals According to Simulated Output Ranges

The next step involved randomly drawing residuals from the previously defined bins and "adding them back" to the simulated mean 10-minute wind output. The procedure of making random draws from an empirical distribution of residuals is called "bootstrapping" residuals.[44] In the context of this study, the technical advisor applied the bootstrapping procedure by randomly drawing[45] a residual from a corresponding bin and adding it to the predicted mean capacity factor value. For example, if a predicted capacity factor value for a missing data point falls within the 10% to 20% interval, a residual value will be randomly drawn from the bin that contains the residuals of the corresponding capacity factor of the historical data when compared with the simulated (or predicted) mean values.

A.4.10 Application of a Non-Linear 3-Step Median Smoother to the Sampled Residuals

After generating a time-series of bootstrapped residuals, the additional step of applying a non-linear smoother to the series, called the "span-3 median smoother" was taken. The span-3 median smoother is a process by which the median of the current, previous, and next period value — in this case, it is calculated by taking the median of residual(t-1), residual(t), residual(t+1)[46] — and using that median as the residual for the current period. The purpose of this approach is two-fold. Firstly, the median smoother ensures that the time-series of residuals resembles the time behavior of wind more closely, with lags affecting the instantaneous results. Secondly, the span-3 median smoother introduces a time-dependency to the data set, which is known to exist in the original wind data.[47]

The technical advisor then added the smoothed time-series of the randomly drawn residuals to the predicted mean capacity factor values for each ten-minute point; then checking the resulting data to make sure the estimates remained within the 0 – 100% capacity factor range.

[44] This name alludes to the fact that, absent prior knowledge of the distribution, the researcher has to pull herself by the bootstraps by drawing randomly from the empirically-derived residual data in order to generate residuals.

[45] Random draws are done with replacement as implemented by the STATA© *bsample* procedure.

[46] For example, see "STATA Base Reference Manual Release 11", Stata Corp. p. 1758; Mosteller, F. and Tukey, John W., "Data Analysis and Regression: A Second Course in Statistics", Addison-Wesley: 1977., pp. 52-58.

[47] Although the non-linear smoothing approach does not exactly replicate the auto-regressive behavior of the wind data, it introduces some similar dependency.

Appendix B

Regression Coefficients and Relative Significance

Regression Results by Month for Glenrock Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.347***	0.242	0.460**	0.278	0.0338	0.554***	0.105	0.576***	0.527***	0.597***	0.669***	0.594***
	(0.125)	*(0.160)*	*(0.184)*	*(0.193)*	*(0.181)*	*(0.140)*	*(0.124)*	*(0.104)*	*(0.140)*	*(0.160)*	*(0.160)*	*(0.168)*
Capacity Factor Foote Creek [t-1]	-0.161	-0.131	-0.186	-0.0782	-0.0667	-0.301	0.0168	-0.181	-0.157	-0.246	-0.310	-0.272
	(0.229)	*(0.288)*	*(0.309)*	*(0.334)*	*(0.298)*	*(0.259)*	*(0.209)*	*(0.174)*	*(0.234)*	*(0.283)*	*(0.283)*	*(0.298)*
Capacity Factor Foote Creek [t-2]	0.0830	0.0687	0.0658	0.0437	-0.0228	0.173	0.0738	0.0989	0.0445	0.154	0.126	0.0644
	(0.249)	*(0.304)*	*(0.322)*	*(0.349)*	*(0.306)*	*(0.283)*	*(0.218)*	*(0.182)*	*(0.241)*	*(0.301)*	*(0.299)*	*(0.313)*
Capacity Factor Foote Creek [t-3]	-0.000558	-0.0146	-0.0358	-0.0237	0.0461	0.00166	0.0998	0.0265	-0.0223	0.0128	-0.0828	-0.0207
	(0.252)	*(0.305)*	*(0.323)*	*(0.350)*	*(0.306)*	*(0.285)*	*(0.218)*	*(0.182)*	*(0.242)*	*(0.303)*	*(0.300)*	*(0.313)*
Capacity Factor Foote Creek [t-4]	0.00538	0.0916	0.0701	0.0163	0.0896	0.176	0.0423	0.0703	0.131	0.100	0.144	0.0531
	(0.249)	*(0.304)*	*(0.322)*	*(0.349)*	*(0.307)*	*(0.282)*	*(0.217)*	*(0.182)*	*(0.242)*	*(0.301)*	*(0.299)*	*(0.313)*
Capacity Factor Foote Creek [t-5]	-0.0399	-0.272	-0.0229	-0.0347	-0.121	-0.212	-0.132	-0.0851	-0.149	-0.275	-0.447	-0.280
	(0.229)	*(0.288)*	*(0.309)*	*(0.334)*	*(0.300)*	*(0.258)*	*(0.208)*	*(0.175)*	*(0.234)*	*(0.283)*	*(0.282)*	*(0.298)*
Capacity Factor Foote Creek [t-6]	0.126	0.561***	0.184	0.166	0.387**	0.405***	0.532***	0.245**	0.526***	0.538***	0.976***	0.710***
	(0.126)	*(0.160)*	*(0.184)*	*(0.193)*	*(0.182)*	*(0.140)*	*(0.123)*	*(0.104)*	*(0.140)*	*(0.160)*	*(0.160)*	*(0.169)*
Number of Observations	2,160	4,032	4,464	4,320	4,464	4,320	4,464	4,464	4,320	4,464	4,320	4,464

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Spanish Fork Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.360**	0.215	0.330	0.503**	0.200	0.0481	-0.0363	-0.183	0.259	0.379**	0.147	0.0538
	(0.175)	*(0.232)*	*(0.217)*	*(0.239)*	*(0.242)*	*(0.220)*	*(0.263)*	*(0.179)*	*(0.196)*	*(0.178)*	*(0.184)*	*(0.167)*
Capacity Factor Foote Creek [t-1]	-0.244	-0.184	-0.187	-0.181	-0.0632	-0.0647	-0.0745	0.0931	-0.0370	-0.103	-0.0451	-0.0854
	(0.328)	*(0.415)*	*(0.366)*	*(0.411)*	*(0.400)*	*(0.406)*	*(0.444)*	*(0.300)*	*(0.333)*	*(0.310)*	*(0.328)*	*(0.300)*
Capacity Factor Foote Creek [t-2]	0.0304	0.0212	0.119	0.0537	0.0487	0.0509	0.0109	0.00608	-0.0965	-0.0136	-0.00668	0.0305
	(0.357)	*(0.439)*	*(0.381)*	*(0.428)*	*(0.411)*	*(0.443)*	*(0.462)*	*(0.313)*	*(0.348)*	*(0.325)*	*(0.348)*	*(0.317)*
Capacity Factor Foote Creek [t-3]	0.0500	0.0332	-0.108	-0.0955	-0.0370	-0.0220	-0.115	-0.0282	0.0344	0.0905	-0.0276	-0.0956
	(0.361)	*(0.441)*	*(0.383)*	*(0.431)*	*(0.408)*	*(0.445)*	*(0.459)*	*(0.314)*	*(0.349)*	*(0.326)*	*(0.350)*	*(0.318)*
Capacity Factor Foote Creek [t-4]	-0.0474	0.0102	-0.00785	0.182	-0.0519	0.0244	0.113	-0.00375	-0.0545	-0.0824	0.0572	0.102
	(0.358)	*(0.440)*	*(0.382)*	*(0.430)*	*(0.407)*	*(0.440)*	*(0.458)*	*(0.312)*	*(0.348)*	*(0.325)*	*(0.349)*	*(0.317)*
Capacity Factor Foote Creek [t-5]	0.0972	-0.0666	0.00720	-0.323	0.0195	-0.111	0.00394	-0.0554	-0.115	0.0815	-0.215	-0.321
	(0.328)	*(0.416)*	*(0.367)*	*(0.412)*	*(0.404)*	*(0.402)*	*(0.440)*	*(0.298)*	*(0.333)*	*(0.310)*	*(0.329)*	*(0.300)*
Capacity Factor Foote Creek [t-6]	-0.128	0.199	-0.0310	0.0558	-0.152	0.0713	-0.00857	0.0280	0.218	-0.154	0.302	0.672***
	(0.175)	*(0.232)*	*(0.217)*	*(0.238)*	*(0.247)*	*(0.219)*	*(0.263)*	*(0.178)*	*(0.196)*	*(0.179)*	*(0.185)*	*(0.168)*
Number of Observations	4,464	4,032	4,464	4,320	4,464	4,320	4,608	8,928	8,640	8,928	8,640	8,928

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Seven Mile Hill Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.519***	0.865***	0.521***	0.705***	1.073***	0.833***	0.722***	0.720***	0.716***	0.787***	0.907***	0.872***
	(0.122)	*(0.115)*	*(0.116)*	*(0.100)*	*(0.113)*	*(0.134)*	*(0.0954)*	*(0.0860)*	*(0.0951)*	*(0.120)*	*(0.118)*	*(0.108)*
Capacity Factor Foote Creek [t-1]	-0.309	-0.366*	-0.00258	-0.218	-0.317*	-0.415*	-0.110	-0.0883	-0.0719	-0.323	-0.375*	-0.387**
	(0.228)	*(0.206)*	*(0.195)*	*(0.173)*	*(0.185)*	*(0.247)*	*(0.161)*	*(0.144)*	*(0.159)*	*(0.212)*	*(0.209)*	*(0.191)*
Capacity Factor Foote Creek [t-2]	0.127	0.135	0.0807	0.104	0.0968	0.247	0.124	0.147	0.106	0.164	0.152	0.103
	(0.249)	*(0.218)*	*(0.203)*	*(0.180)*	*(0.188)*	*(0.271)*	*(0.169)*	*(0.150)*	*(0.164)*	*(0.225)*	*(0.221)*	*(0.198)*
Capacity Factor Foote Creek [t-3]	-0.0283	-0.0230	-0.0466	0.00180	0.000586	0.00521	0.161	0.0237	-0.0534	0.00176	-0.0393	-0.0567
	(0.251)	*(0.218)*	*(0.203)*	*(0.180)*	*(0.188)*	*(0.273)*	*(0.169)*	*(0.151)*	*(0.164)*	*(0.227)*	*(0.222)*	*(0.198)*
Capacity Factor Foote Creek [t-4]	0.126	0.120	0.109	0.0881	0.0325	0.140	0.0899	0.0209	0.105	0.0975	0.145	0.0793
	(0.249)	*(0.218)*	*(0.203)*	*(0.180)*	*(0.188)*	*(0.271)*	*(0.169)*	*(0.151)*	*(0.164)*	*(0.225)*	*(0.221)*	*(0.198)*
Capacity Factor Foote Creek [t-5]	-0.302	-0.382*	-0.0425	-0.0821	-0.0763	-0.120	-0.0786	-0.0998	-0.0207	-0.175	-0.295	-0.223
	(0.228)	*(0.206)*	*(0.195)*	*(0.172)*	*(0.184)*	*(0.248)*	*(0.163)*	*(0.145)*	*(0.160)*	*(0.212)*	*(0.209)*	*(0.189)*
Capacity Factor Foote Creek [t-6]	0.519***	0.770***	0.336***	0.453***	0.350***	0.217	0.269***	0.242***	0.337***	0.493***	0.805***	0.521***
	(0.121)	*(0.115)*	*(0.116)*	*(0.100)*	*(0.111)*	*(0.135)*	*(0.0961)*	*(0.0867)*	*(0.0955)*	*(0.120)*	*(0.118)*	*(0.107)*
Number of Observations	4,464	4,032	4,464	4,320	4,464	4,320	4,464	4,464	4,320	4,464	4,320	4,608

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Mountain Wind Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.522***	0.614***	0.639***	0.372**	0.338***	0.303***	0.749***	0.495***	0.435***	0.527***	0.664***	0.806***
	(0.175)	*(0.217)*	*(0.129)*	*(0.160)*	*(0.128)*	*(0.110)*	*(0.138)*	*(0.149)*	*(0.154)*	*(0.123)*	*(0.126)*	*(0.124)*
Capacity Factor Foote Creek [t-1]	-0.333	-0.291	-0.183	-0.146	-0.0689	-0.158	-0.262	-0.184	-0.158	-0.204	-0.263	-0.373*
	(0.329)	*(0.389)*	*(0.217)*	*(0.276)*	*(0.211)*	*(0.202)*	*(0.233)*	*(0.250)*	*(0.257)*	*(0.211)*	*(0.224)*	*(0.222)*
Capacity Factor Foote Creek [t-2]	0.129	0.0805	0.0961	0.0198	0.0127	0.134	0.0493	0.102	0.0790	0.0825	0.135	0.104
	(0.359)	*(0.411)*	*(0.225)*	*(0.288)*	*(0.216)*	*(0.221)*	*(0.243)*	*(0.261)*	*(0.265)*	*(0.220)*	*(0.237)*	*(0.235)*
Capacity Factor Foote Creek [t-3]	-0.0548	-0.0821	-0.0349	-0.0195	0.0322	0.000107	0.137	0.00232	-0.0552	-0.00161	-0.0200	-0.102
	(0.362)	*(0.413)*	*(0.226)*	*(0.289)*	*(0.216)*	*(0.223)*	*(0.243)*	*(0.262)*	*(0.265)*	*(0.221)*	*(0.238)*	*(0.236)*
Capacity Factor Foote Creek [t-4]	0.146	0.0787	0.0767	0.0641	0.0273	0.0867	-0.0219	0.0359	0.118	0.0481	0.0241	0.0787
	(0.359)	*(0.412)*	*(0.225)*	*(0.288)*	*(0.216)*	*(0.221)*	*(0.243)*	*(0.261)*	*(0.265)*	*(0.220)*	*(0.237)*	*(0.235)*
Capacity Factor Foote Creek [t-5]	-0.339	-0.0256	-0.0428	-0.210	-0.0462	-0.0963	0.0567	-0.131	-0.174	-0.131	-0.0237	-0.287
	(0.329)	*(0.390)*	*(0.217)*	*(0.276)*	*(0.211)*	*(0.202)*	*(0.234)*	*(0.251)*	*(0.257)*	*(0.211)*	*(0.224)*	*(0.222)*
Capacity Factor Foote Creek [t-6]	0.545***	0.0835	0.305**	0.445***	0.400***	0.248**	0.0834	0.325**	0.676***	0.314**	0.112	0.580***
	(0.175)	*(0.217)*	*(0.129)*	*(0.160)*	*(0.128)*	*(0.110)*	*(0.138)*	*(0.150)*	*(0.154)*	*(0.123)*	*(0.126)*	*(0.124)*
Number of Observations	4,464	4,032	4,464	4,320	4,464	4,320	4,464	4,464	4,608	8,928	8,640	8,928

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Marengo Predicted by Combine Hills

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Combine Hills [t]	0.486***	0.372***	0.360***	0.482***	0.487***	0.234***	0.307***	0.295***	0.353***	0.594***	0.493***	0.760***
	(0.182)	(0.113)	(0.0969)	(0.122)	(0.0869)	(0.0862)	(0.0803)	(0.0722)	(0.0805)	(0.0868)	(0.0903)	(0.111)
Capacity Factor Combine Hills [t-1]	-0.271	-0.109	-0.129	-0.235	-0.226	-0.131	-0.186	-0.146	-0.160	-0.328**	-0.228	-0.336*
	(0.336)	(0.197)	(0.177)	(0.219)	(0.157)	(0.158)	(0.145)	(0.136)	(0.147)	(0.161)	(0.164)	(0.199)
Capacity Factor Combine Hills [t-2]	0.182	0.151	0.135	0.0636	0.0711	0.0448	0.0484	0.0365	0.0837	0.134	0.113	0.170
	(0.364)	(0.211)	(0.192)	(0.230)	(0.166)	(0.168)	(0.150)	(0.146)	(0.158)	(0.173)	(0.175)	(0.211)
Capacity Factor Combine Hills [t-3]	-0.00779	-0.0543	-0.165	-0.0483	-0.0264	0.00555	0.0109	-0.00229	-0.128	-0.109	-0.0854	0.0328
	(0.365)	(0.212)	(0.194)	(0.231)	(0.166)	(0.168)	(0.150)	(0.147)	(0.160)	(0.174)	(0.176)	(0.212)
Capacity Factor Combine Hills [t-4]	0.0761	0.0545	0.243	0.113	0.138	0.0672	-0.0142	0.112	0.198	0.168	0.155	0.116
	(0.364)	(0.209)	(0.192)	(0.230)	(0.167)	(0.166)	(0.150)	(0.147)	(0.158)	(0.173)	(0.175)	(0.211)
Capacity Factor Combine Hills [t-5]	-0.0275	-0.145	-0.556***	-0.508**	-0.325**	-0.393**	-0.438***	-0.484***	-0.406***	-0.458***	-0.294*	-0.197
	(0.336)	(0.196)	(0.177)	(0.219)	(0.158)	(0.156)	(0.145)	(0.136)	(0.147)	(0.161)	(0.163)	(0.199)
Capacity Factor Combine Hills [t-6]	0.179	0.452***	1.056***	0.950***	0.752***	0.839***	0.944***	0.879***	0.841***	0.839***	0.719***	0.483***
	(0.181)	(0.112)	(0.0968)	(0.122)	(0.0872)	(0.0853)	(0.0800)	(0.0720)	(0.0801)	(0.0867)	(0.0901)	(0.111)
Number of Observations	4,464	4,032	4,464	4,320	4,464	5,040	8,928	8,928	8,640	8,928	8,640	8,928

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Goodnoe Predicted by Leaning Juniper

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Leaning Juniper [t]	0.811***	0.730***	0.841***	0.877***	0.901***	0.762***	0.755***	0.703***	0.805***	0.682***	0.776***	0.748***
	(0.103)	(0.126)	(0.0744)	(0.0820)	(0.0869)	(0.0520)	(0.0601)	(0.0541)	(0.0755)	(0.0552)	(0.0675)	(0.118)
Capacity Factor Leaning Juniper [t-1]	-0.412**	-0.445*	-0.321**	-0.379***	-0.420***	-0.320***	-0.283***	-0.279***	-0.412***	-0.233**	-0.319***	-0.366*
	(0.189)	(0.242)	(0.130)	(0.147)	(0.159)	(0.0910)	(0.103)	(0.0953)	(0.138)	(0.0961)	(0.119)	(0.217)
Capacity Factor Leaning Juniper [t-2]	0.222	0.166	0.0314	0.164	0.177	0.0852	0.116	0.167*	0.161	0.120	0.160	0.166
	(0.205)	(0.267)	(0.135)	(0.157)	(0.171)	(0.0956)	(0.108)	(0.101)	(0.148)	(0.102)	(0.126)	(0.233)
Capacity Factor Leaning Juniper [t-3]	-0.0369	-0.0679	0.0631	0.0348	-0.00515	0.0395	-0.0405	-0.0296	0.0255	0.0218	-0.0387	-0.0299
	(0.206)	(0.270)	(0.135)	(0.157)	(0.172)	(0.0960)	(0.108)	(0.102)	(0.148)	(0.102)	(0.127)	(0.234)
Capacity Factor Leaning Juniper [t-4]	0.127	0.123	0.0597	0.0691	0.0812	0.0867	0.0846	0.127	0.0876	0.0641	0.106	0.114
	(0.205)	(0.267)	(0.135)	(0.157)	(0.172)	(0.0958)	(0.108)	(0.101)	(0.148)	(0.102)	(0.126)	(0.233)
Capacity Factor Leaning Juniper [t-5]	-0.130	-0.291	0.00342	-0.127	-0.102	-0.121	-0.135	-0.142	-0.180	-0.0979	-0.122	-0.205
	(0.189)	(0.242)	(0.130)	(0.147)	(0.161)	(0.0914)	(0.103)	(0.0952)	(0.138)	(0.0962)	(0.119)	(0.217)
Capacity Factor Leaning Juniper [t-6]	0.324***	0.470***	0.267***	0.294***	0.305***	0.291***	0.339***	0.343***	0.360***	0.349***	0.389***	0.400***
	(0.103)	(0.126)	(0.0744)	(0.0819)	(0.0873)	(0.0521)	(0.0601)	(0.0540)	(0.0757)	(0.0551)	(0.0675)	(0.118)
Number of Observations	4,464	4,032	4,464	4,320	4,608	8,640	8,928	8,928	8,640	8,928	8,640	8,928

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Top of the World Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.368***	0.327***	0.275***	0.194***	0.0788**	0.101***	0.0683***	0.0724***	0.137***	0.202***	0.395***	0.416***
	(0.0643)	*(0.0623)*	*(0.0500)*	*(0.0391)*	*(0.0316)*	*(0.0243)*	*(0.0223)*	*(0.0260)*	*(0.0300)*	*(0.0449)*	*(0.0619)*	*(0.0577)*
Capacity Factor Foote Creek [t-1]	0.0545	0.0482	0.0451	0.00184	0.0524	0.00127	0.0123	-0.0122	0.0202	0.0312	0.103	0.0662
	(0.0843)	*(0.0828)*	*(0.0674)*	*(0.0521)*	*(0.0414)*	*(0.0327)*	*(0.0298)*	*(0.0355)*	*(0.0412)*	*(0.0593)*	*(0.0794)*	*(0.0768)*
Capacity Factor Foote Creek [t-2]	-0.0469	0.0164	-0.0208	0.0212	0.0251	0.0268	7.50e-05	0.0251	0.0246	0.00170	-0.0110	0.00624
	(0.0857)	*(0.0835)*	*(0.0677)*	*(0.0523)*	*(0.0415)*	*(0.0327)*	*(0.0297)*	*(0.0355)*	*(0.0412)*	*(0.0596)*	*(0.0805)*	*(0.0771)*
Capacity Factor Foote Creek [t-3]	-0.0369	-0.0183	-0.00578	0.0170	0.00300	0.0202	0.0107	0.0229	0.00661	0.000210	0.0185	-0.0236
	(0.0855)	*(0.0835)*	*(0.0677)*	*(0.0523)*	*(0.0415)*	*(0.0327)*	*(0.0297)*	*(0.0355)*	*(0.0413)*	*(0.0596)*	*(0.0806)*	*(0.0774)*
Capacity Factor Foote Creek [t-4]	-0.0152	0.00696	-0.00881	0.0368	0.0260	0.0321	0.0133	-0.00532	0.00566	0.0176	-0.0311	-0.00378
	(0.0856)	*(0.0836)*	*(0.0678)*	*(0.0522)*	*(0.0415)*	*(0.0328)*	*(0.0296)*	*(0.0356)*	*(0.0413)*	*(0.0596)*	*(0.0805)*	*(0.0774)*
Capacity Factor Foote Creek [t-5]	0.0884	0.0553	0.0489	0.0240	0.0380	0.0151	-0.0174	0.0350	0.00410	0.0615	0.0477	0.0482
	(0.0844)	*(0.0828)*	*(0.0674)*	*(0.0521)*	*(0.0414)*	*(0.0328)*	*(0.0296)*	*(0.0356)*	*(0.0412)*	*(0.0592)*	*(0.0796)*	*(0.0769)*
Capacity Factor Foote Creek [t-6]	0.365***	0.239***	0.243***	0.238***	0.144***	0.159***	0.0577***	0.125***	0.153***	0.249***	0.266***	0.365***
	(0.0644)	*(0.0624)*	*(0.0500)*	*(0.0391)*	*(0.0316)*	*(0.0243)*	*(0.0222)*	*(0.0261)*	*(0.0300)*	*(0.0448)*	*(0.0620)*	*(0.0578)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Three Buttes Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.347***	0.284***	0.299***	0.201***	0.0910***	0.122***	0.0774***	0.0606**	0.128***	0.184***	0.394***	0.389***
	(0.0602)	*(0.0612)*	*(0.0465)*	*(0.0406)*	*(0.0314)*	*(0.0250)*	*(0.0217)*	*(0.0273)*	*(0.0287)*	*(0.0447)*	*(0.0604)*	*(0.0559)*
Capacity Factor Foote Creek [t-1]	0.0552	0.0508	0.0395	0.00591	0.0290	0.0116	0.00723	0.0320	0.00576	0.0335	0.0977	0.0541
	(0.0789)	*(0.0813)*	*(0.0627)*	*(0.0540)*	*(0.0411)*	*(0.0337)*	*(0.0290)*	*(0.0372)*	*(0.0394)*	*(0.0588)*	*(0.0776)*	*(0.0747)*
Capacity Factor Foote Creek [t-2]	-0.0260	0.00141	-0.00890	0.0211	0.0119	0.0118	0.0286	0.0344	0.0199	0.0135	-0.0355	0.0155
	(0.0801)	*(0.0821)*	*(0.0630)*	*(0.0542)*	*(0.0411)*	*(0.0338)*	*(0.0290)*	*(0.0372)*	*(0.0394)*	*(0.0592)*	*(0.0787)*	*(0.0754)*
Capacity Factor Foote Creek [t-3]	-0.0199	0.0114	0.0108	0.0197	0.0300	0.0244	-0.0105	0.00457	0.0208	0.0216	-0.000275	-0.00758
	(0.0798)	*(0.0820)*	*(0.0631)*	*(0.0542)*	*(0.0411)*	*(0.0338)*	*(0.0290)*	*(0.0372)*	*(0.0394)*	*(0.0592)*	*(0.0787)*	*(0.0755)*
Capacity Factor Foote Creek [t-4]	-0.0358	-0.0225	-0.00289	-0.000622	0.0185	0.0152	0.000939	0.0212	0.00602	0.00727	-0.0350	-0.0196
	(0.0800)	*(0.0821)*	*(0.0630)*	*(0.0542)*	*(0.0412)*	*(0.0338)*	*(0.0289)*	*(0.0372)*	*(0.0394)*	*(0.0593)*	*(0.0788)*	*(0.0755)*
Capacity Factor Foote Creek [t-5]	0.0651	0.0465	0.00235	0.0502	0.0142	0.0313	0.0117	-0.00139	0.00699	0.0327	0.0617	0.0364
	(0.0789)	*(0.0814)*	*(0.0626)*	*(0.0540)*	*(0.0411)*	*(0.0338)*	*(0.0289)*	*(0.0373)*	*(0.0394)*	*(0.0590)*	*(0.0778)*	*(0.0751)*
Capacity Factor Foote Creek [t-6]	0.329***	0.270***	0.206***	0.221***	0.156***	0.162***	0.0388*	0.119***	0.154***	0.244***	0.242***	0.331***
	(0.0603)	*(0.0613)*	*(0.0465)*	*(0.0406)*	*(0.0314)*	*(0.0250)*	*(0.0216)*	*(0.0274)*	*(0.0286)*	*(0.0446)*	*(0.0605)*	*(0.0563)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Dunlap Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.450***	0.292***	0.352***	0.234***	0.114***	0.161***	0.104***	0.134***	0.176***	0.278***	0.408***	0.447***
	(0.0478)	*(0.0441)*	*(0.0378)*	*(0.0285)*	*(0.0237)*	*(0.0186)*	*(0.0140)*	*(0.0168)*	*(0.0214)*	*(0.0366)*	*(0.0458)*	*(0.0488)*
Capacity Factor Foote Creek [t-1]	0.0665	0.0726	0.0582	0.0495	0.0409	0.0313	0.0518***	0.0298	0.0542*	0.0676	0.112*	0.0523
	(0.0624)	*(0.0587)*	*(0.0510)*	*(0.0379)*	*(0.0310)*	*(0.0251)*	*(0.0186)*	*(0.0228)*	*(0.0294)*	*(0.0483)*	*(0.0588)*	*(0.0652)*
Capacity Factor Foote Creek [t-2]	-0.00458	-0.0240	-0.0135	0.0126	0.0678**	0.0369	0.0250	0.0311	0.0447	0.00626	0.00486	0.00843
	(0.0635)	*(0.0592)*	*(0.0513)*	*(0.0381)*	*(0.0311)*	*(0.0251)*	*(0.0186)*	*(0.0228)*	*(0.0294)*	*(0.0486)*	*(0.0596)*	*(0.0655)*
Capacity Factor Foote Creek [t-3]	-0.0151	0.0472	-0.00555	0.00570	0.0440	0.0429*	0.0163	0.0196	0.0232	-0.00101	-0.0307	-0.0148
	(0.0636)	*(0.0591)*	*(0.0513)*	*(0.0381)*	*(0.0311)*	*(0.0251)*	*(0.0186)*	*(0.0228)*	*(0.0294)*	*(0.0486)*	*(0.0595)*	*(0.0656)*
Capacity Factor Foote Creek [t-4]	-0.0355	-0.0389	0.00531	0.0189	0.0356	0.0318	0.0173	0.0247	-0.00119	-0.000509	0.00812	0.0296
	(0.0635)	*(0.0592)*	*(0.0513)*	*(0.0380)*	*(0.0311)*	*(0.0251)*	*(0.0186)*	*(0.0228)*	*(0.0294)*	*(0.0486)*	*(0.0595)*	*(0.0657)*
Capacity Factor Foote Creek [t-5]	0.0849	0.0637	0.00670	0.0516	0.0435	0.0361	-0.00205	0.0201	-0.00276	0.0434	0.0525	0.0145
	(0.0624)	*(0.0587)*	*(0.0509)*	*(0.0379)*	*(0.0310)*	*(0.0251)*	*(0.0186)*	*(0.0228)*	*(0.0294)*	*(0.0484)*	*(0.0588)*	*(0.0652)*
Capacity Factor Foote Creek [t-6]	0.367***	0.385***	0.282***	0.239***	0.150***	0.119***	0.0783***	0.120***	0.147***	0.289***	0.277***	0.388***
	(0.0476)	*(0.0440)*	*(0.0377)*	*(0.0284)*	*(0.0236)*	*(0.0186)*	*(0.0140)*	*(0.0168)*	*(0.0214)*	*(0.0366)*	*(0.0457)*	*(0.0489)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Rolling Hills Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.372***	0.334***	0.310***	0.213***	0.0919***	0.119***	0.0854***	0.0756***	0.144***	0.224***	0.392***	0.414***
	(0.0635)	*(0.0631)*	*(0.0490)*	*(0.0405)*	*(0.0318)*	*(0.0252)*	*(0.0223)*	*(0.0267)*	*(0.0303)*	*(0.0457)*	*(0.0619)*	*(0.0590)*
Capacity Factor Foote Creek [t-1]	0.0571	0.0678	0.0577	0.0329	0.0321	0.0383	-0.00870	0.00443	0.0205	0.0232	0.0809	0.0331
	(0.0832)	*(0.0838)*	*(0.0660)*	*(0.0539)*	*(0.0416)*	*(0.0340)*	*(0.0298)*	*(0.0362)*	*(0.0417)*	*(0.0604)*	*(0.0795)*	*(0.0788)*
Capacity Factor Foote Creek [t-2]	-0.0482	-0.00447	-0.0226	0.0145	0.0318	0.0134	0.0186	0.0355	-0.00162	0.0120	0.0158	0.0364
	(0.0846)	*(0.0846)*	*(0.0664)*	*(0.0541)*	*(0.0417)*	*(0.0341)*	*(0.0297)*	*(0.0362)*	*(0.0418)*	*(0.0605)*	*(0.0804)*	*(0.0791)*
Capacity Factor Foote Creek [t-3]	-0.0268	-0.0390	-0.0218	0.0237	0.0244	0.0130	0.0108	0.0189	0.0227	0.00717	-0.0234	-0.00569
	(0.0845)	*(0.0846)*	*(0.0664)*	*(0.0541)*	*(0.0417)*	*(0.0340)*	*(0.0297)*	*(0.0362)*	*(0.0419)*	*(0.0607)*	*(0.0803)*	*(0.0792)*
Capacity Factor Foote Creek [t-4]	-0.0226	-0.00151	-0.0163	0.0253	0.0162	0.0160	0.0123	0.0139	0.00500	0.01000	-0.00365	0.00189
	(0.0844)	*(0.0847)*	*(0.0664)*	*(0.0541)*	*(0.0417)*	*(0.0340)*	*(0.0297)*	*(0.0362)*	*(0.0418)*	*(0.0607)*	*(0.0804)*	*(0.0793)*
Capacity Factor Foote Creek [t-5]	0.0468	0.0350	0.0432	0.0216	0.0334	0.0344	-0.0196	0.0162	0.0129	0.0313	0.0881	0.0672
	(0.0830)	*(0.0838)*	*(0.0659)*	*(0.0539)*	*(0.0416)*	*(0.0340)*	*(0.0297)*	*(0.0362)*	*(0.0417)*	*(0.0604)*	*(0.0796)*	*(0.0788)*
Capacity Factor Foote Creek [t-6]	0.383***	0.279***	0.235***	0.231***	0.150***	0.163***	0.0720***	0.113***	0.162***	0.269***	0.225***	0.312***
	(0.0633)	*(0.0632)*	*(0.0489)*	*(0.0405)*	*(0.0318)*	*(0.0252)*	*(0.0222)*	*(0.0266)*	*(0.0303)*	*(0.0457)*	*(0.0620)*	*(0.0593)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Rock River Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.697***	0.614***	0.723***	0.733***	0.702***	0.708***	0.727***	0.685***	0.746***	0.680***	0.700***	0.681***
	(0.0257)	*(0.0206)*	*(0.0198)*	*(0.0182)*	*(0.0126)*	*(0.0129)*	*(0.0116)*	*(0.0128)*	*(0.0145)*	*(0.0187)*	*(0.0245)*	*(0.0261)*
Capacity Factor Foote Creek [t-1]	0.169***	0.224***	0.190***	0.173***	0.141***	0.105***	0.104***	0.146***	0.127***	0.185***	0.212***	0.167***
	(0.0337)	*(0.0275)*	*(0.0269)*	*(0.0242)*	*(0.0165)*	*(0.0174)*	*(0.0155)*	*(0.0174)*	*(0.0199)*	*(0.0247)*	*(0.0316)*	*(0.0350)*
Capacity Factor Foote Creek [t-2]	0.0506	0.0688**	0.0670**	0.0322	0.0253	0.0207	0.0247	0.0315*	-0.0103	0.0492**	0.0506	0.0486
	(0.0343)	*(0.0278)*	*(0.0271)*	*(0.0244)*	*(0.0165)*	*(0.0174)*	*(0.0155)*	*(0.0174)*	*(0.0199)*	*(0.0248)*	*(0.0320)*	*(0.0354)*
Capacity Factor Foote Creek [t-3]	0.0220	0.0364	0.0287	-0.0120	0.0291*	0.0512***	0.0268*	0.0158	0.0310	0.00557	0.0150	-0.00890
	(0.0344)	*(0.0278)*	*(0.0272)*	*(0.0244)*	*(0.0166)*	*(0.0175)*	*(0.0155)*	*(0.0174)*	*(0.0199)*	*(0.0249)*	*(0.0321)*	*(0.0355)*
Capacity Factor Foote Creek [t-4]	0.000164	-0.0105	0.0138	0.00796	0.0376**	-0.0108	0.00877	0.0250	0.0424**	0.0261	-0.00958	0.0228
	(0.0346)	*(0.0279)*	*(0.0272)*	*(0.0244)*	*(0.0166)*	*(0.0175)*	*(0.0155)*	*(0.0174)*	*(0.0199)*	*(0.0249)*	*(0.0321)*	*(0.0356)*
Capacity Factor Foote Creek [t-5]	0.000294	0.0494*	0.0205	0.00953	0.0165	0.0349**	0.0211	0.0118	0.00483	0.0240	0.00374	0.0274
	(0.0341)	*(0.0278)*	*(0.0273)*	*(0.0243)*	*(0.0166)*	*(0.0175)*	*(0.0155)*	*(0.0175)*	*(0.0199)*	*(0.0248)*	*(0.0318)*	*(0.0356)*
Capacity Factor Foote Creek [t-6]	0.116***	0.0503**	-0.0140	0.0660***	0.0248*	0.0505***	0.0125	0.0255**	0.0436***	0.0427**	0.0719***	0.126***
	(0.0259)	*(0.0209)*	*(0.0203)*	*(0.0183)*	*(0.0126)*	*(0.0130)*	*(0.0117)*	*(0.0129)*	*(0.0145)*	*(0.0189)*	*(0.0247)*	*(0.0268)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for McFadden Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.461***	0.329***	0.284***	0.297***	0.196***	0.168***	0.155***	0.177***	0.220***	0.240***	0.297***	0.404***
	(0.0522)	*(0.0429)*	*(0.0363)*	*(0.0304)*	*(0.0216)*	*(0.0205)*	*(0.0196)*	*(0.0221)*	*(0.0231)*	*(0.0322)*	*(0.0484)*	*(0.0446)*
Capacity Factor Foote Creek [t-1]	0.0625	0.0793	0.0563	0.139***	0.141***	0.144***	0.145***	0.106***	0.160***	0.124***	0.122**	0.0597
	(0.0684)	*(0.0571)*	*(0.0490)*	*(0.0405)*	*(0.0283)*	*(0.0276)*	*(0.0260)*	*(0.0301)*	*(0.0317)*	*(0.0424)*	*(0.0622)*	*(0.0596)*
Capacity Factor Foote Creek [t-2]	-0.0579	0.0406	0.0375	0.0891**	0.194***	0.182***	0.202***	0.176***	0.118***	0.110***	0.0247	0.0458
	(0.0696)	*(0.0576)*	*(0.0493)*	*(0.0407)*	*(0.0283)*	*(0.0276)*	*(0.0260)*	*(0.0301)*	*(0.0317)*	*(0.0426)*	*(0.0628)*	*(0.0598)*
Capacity Factor Foote Creek [t-3]	-0.00530	0.0210	0.0248	0.0507	0.0834***	0.130***	0.0969***	0.1000***	0.0786**	0.0880**	0.0279	0.00789
	(0.0695)	*(0.0575)*	*(0.0493)*	*(0.0407)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0629)*	*(0.0600)*
Capacity Factor Foote Creek [t-4]	0.0353	0.00324	0.00366	0.0158	0.0435	0.0303	0.0332	0.0287	0.0465	0.0255	0.0414	-0.0257
	(0.0694)	*(0.0576)*	*(0.0492)*	*(0.0407)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0629)*	*(0.0602)*
Capacity Factor Foote Creek [t-5]	0.0822	0.0794	0.0859*	0.0525	0.0447	0.0170	0.00342	0.0192	0.00913	0.0133	0.0704	0.0689
	(0.0683)	*(0.0571)*	*(0.0489)*	*(0.0405)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0622)*	*(0.0596)*
Capacity Factor Foote Creek [t-6]	0.322***	0.328***	0.377***	0.201***	0.107***	0.0697***	0.0844***	0.0662***	0.0966***	0.228***	0.254***	0.423***
	(0.0520)	*(0.0429)*	*(0.0362)*	*(0.0304)*	*(0.0216)*	*(0.0206)*	*(0.0195)*	*(0.0221)*	*(0.0231)*	*(0.0322)*	*(0.0483)*	*(0.0448)*
Number of Observations	*13,386*	*12,240*	*13,392*	*12,960*	*13,392*	*12,960*	*13,392*	*13,392*	*12,960*	*13,392*	*12,960*	*13,392*

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for High Plains Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.461***	0.329***	0.284***	0.297***	0.196***	0.168***	0.155***	0.177***	0.220***	0.240***	0.297***	0.404***
	(0.0522)	*(0.0429)*	*(0.0363)*	*(0.0304)*	*(0.0216)*	*(0.0205)*	*(0.0196)*	*(0.0221)*	*(0.0231)*	*(0.0322)*	*(0.0484)*	*(0.0446)*
Capacity Factor Foote Creek [t-1]	0.0625	0.0793	0.0563	0.139***	0.141***	0.144***	0.145***	0.106***	0.160***	0.124***	0.122**	0.0597
	(0.0684)	*(0.0571)*	*(0.0490)*	*(0.0405)*	*(0.0283)*	*(0.0276)*	*(0.0260)*	*(0.0301)*	*(0.0317)*	*(0.0424)*	*(0.0622)*	*(0.0596)*
Capacity Factor Foote Creek [t-2]	-0.0579	0.0406	0.0375	0.0891**	0.194***	0.182***	0.202***	0.176***	0.118***	0.110***	0.0247	0.0458
	(0.0696)	*(0.0576)*	*(0.0493)*	*(0.0407)*	*(0.0283)*	*(0.0276)*	*(0.0260)*	*(0.0301)*	*(0.0317)*	*(0.0426)*	*(0.0628)*	*(0.0598)*
Capacity Factor Foote Creek [t-3]	-0.00530	0.0210	0.0248	0.0507	0.0834***	0.130***	0.0969***	0.1000***	0.0786**	0.0880**	0.0279	0.00789
	(0.0695)	*(0.0575)*	*(0.0493)*	*(0.0407)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0629)*	*(0.0600)*
Capacity Factor Foote Creek [t-4]	0.0353	0.00324	0.00366	0.0158	0.0435	0.0303	0.0332	0.0287	0.0465	0.0255	0.0414	-0.0257
	(0.0694)	*(0.0576)*	*(0.0492)*	*(0.0407)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0629)*	*(0.0602)*
Capacity Factor Foote Creek [t-5]	0.0822	0.0794	0.0859*	0.0525	0.0447	0.0170	0.00342	0.0192	0.00913	0.0133	0.0704	0.0689
	(0.0683)	*(0.0571)*	*(0.0489)*	*(0.0405)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0622)*	*(0.0596)*
Capacity Factor Foote Creek [t-6]	0.322***	0.328***	0.377***	0.201***	0.107***	0.0697***	0.0844***	0.0662***	0.0966***	0.228***	0.254***	0.423***
	(0.0520)	*(0.0429)*	*(0.0362)*	*(0.0304)*	*(0.0216)*	*(0.0206)*	*(0.0195)*	*(0.0221)*	*(0.0231)*	*(0.0322)*	*(0.0483)*	*(0.0448)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** $p<0.01$, ** $p<0.05$, * $p<0.1$

Appendix C

Operating Reserve Demand Seasonal Detail

This Appendix presents the monthly component operating reserve service demand calculated for the PacifiCorp East and West Balancing Authority Areas in the Study. The 1,372 MW and 1,833 MW penetration scenarios include some simulated wind data; the load-only and 425 MW penetration scenarios do not.

Table C1.West Balancing Authority Area, Load Only

	Load Following		Regulation	
	Up	Down	Up	Down
January	127	129	125	82
February	93	103	111	73
March	114	115	109	77
April	84	87	103	65
May	93	101	95	72
June	82	83	78	63
July	93	96	69	64
August	79	84	65	60
September	96	104	88	64
October	83	83	98	62
November	149	166	127	95
December	125	116	101	86

Table C2.West Balancing Authority Area, 425 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	132	134	131	91
February	104	110	117	82
March	128	124	118	92
April	96	96	110	78
May	108	109	102	84
June	103	96	88	80
July	110	105	78	79
August	98	94	76	77
September	105	107	94	73
October	97	88	104	74
November	157	169	133	103
December	132	121	106	94

Table C3. West Balancing Authority area, 1,372 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	153	150	171	139
February	122	122	152	129
March	160	152	152	140
April	133	122	150	121
May	135	131	136	123
June	131	123	127	118
July	128	122	110	104
August	118	113	103	104
September	125	121	118	101
October	124	105	126	104
November	181	180	152	131
December	159	138	142	131

Table C4. West Balancing Authority area, 1,833 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	153	150	171	139
February	124	124	152	129
March	162	154	152	140
April	136	123	150	121
May	137	133	136	123
June	133	125	127	118
July	129	123	110	104
August	120	115	103	104
September	126	122	118	101
October	125	106	126	104
November	182	180	152	131
December	161	139	142	131

Table C5. East Balancing Authority area, Load Only

	Load Following		Regulation	
	Up	Down	Up	Down
January	127	131	150	110
February	117	122	131	98
March	135	138	122	102
April	105	103	145	95
May	146	145	133	114
June	143	152	134	114
July	157	155	130	112
August	162	162	122	111
September	144	162	127	105
October	139	146	116	97
November	154	164	161	110
December	145	149	182	112

Table C6. East Balancing Authority Area, 425 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	132	135	152	113
February	120	125	134	101
March	139	142	124	105
April	112	107	148	99
May	151	148	137	118
June	148	155	137	118
July	161	157	132	115
August	165	164	124	114
September	149	165	130	109
October	143	150	119	101
November	158	168	163	113
December	150	154	185	116

Table C7. East Balancing Authority Area, 1,372 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	187	193	201	175
February	201	195	210	189
March	212	209	207	200
April	193	174	212	182
May	204	184	183	179
June	205	192	189	185
July	205	177	170	172
August	204	187	164	166
September	219	203	185	177
October	218	211	202	192
November	230	227	232	197
December	212	228	253	207

Table C8. East Balancing Authority area, 1,833 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	240	262	250	241
February	256	262	264	247
March	247	247	235	236
April	236	213	243	223
May	228	205	203	202
June	232	210	204	202
July	220	185	177	183
August	216	197	176	179
September	245	222	201	199
October	257	251	235	230
November	276	290	279	259
December	291	299	300	266

APPENDIX J – STOCHASTIC LOSS OF LOAD STUDY

Introduction

PacifiCorp evaluates the desired level of capacity planning reserves for each integrated resource plan. For the 2011 IRP, the Company conducted a stochastic loss of load study to help identify the target capacity planning reserve margin (PRM) to use for resource portfolio development. This study utilized the Company's stochastic production cost simulation system, Planning and Risk (PaR), to determine the relationship between PRM and resource adequacy as measured by Loss of Load Probability (LOLP) index. Loss of load probability represents the probability that generation in a given hour is insufficient to serve load. Accumulating the number of hours for which the system experiences unserved load over a given period, typically one year, yields the LOLP index. Once the relationship between LOLP and PRM is established for PacifiCorp's system, a target LOLP level is selected to determine the PRM for subsequent resource portfolio development. This report describes the loss of load study and modeling assumptions, the selection of a target loss of load criterion, and the adoption of a PRM for portfolio development. The last comprehensive stochastic study conducted was for PacifiCorp's 2004 IRP.[48] Major differences between this study and the last one include (1) significantly more wind resources and incorporation of incremental wind operating reserves in the resource portfolio simulations, (2) expansion of the transmission topology from two bubbles to 26, and (3) incorporation of energy efficiency programs as a resource with a reserve credit rather than a reduction to the load forecast.

Note that while this study reports the incremental resource cost for achieving a given loss of load frequency and associated reserve margin level using a standard reliability resource type, it does not assess the trade-off between reliability and cost or the optimal resource mix to achieve a given reliability level. PacifiCorp compares different resource portfolios based on the amount and cost of unserved load (megawatt-hours of "Energy Not Served" or ENS) resulting from stochastic simulations of many portfolios built to meet a given PRM level. This stochastic analysis reveals the reliability impacts and costs associated with different resource mixes.

Loss of Load Probability Metrics

The metric used to derive the LOLP index is Loss of Load Hours (LOLH). The PaR model records a LOLH event when load is not met for an hour. This condition results from unit outages that reduce available generation capacity in a load area below the load derived from the Monte Carlo draws conducted by the PaR model. The LOLH event also has an associated Energy Not Served value, which is the magnitude of the lost load for the hour.

[48] See Appendix N of the 2004 IRP Technical Appendix Volume.

The PaR model's reported LOLP index is the average number of LOLH events for PacifiCorp's 100-iteration Monte Carlo production cost simulation. This measure is thus a likelihood of experiencing a shortfall in any given hour for the stochastic Monte Carlo simulation.[49]

Simulation Period

PacifiCorp selected 2014 as the simulation test year for the LOLP study. This year aligns with the start of the 2014-2016 resource acquisition period targeted by the Company's All Source RFP issued to the market on December 2, 16 2009. This year also aligns with major planned Energy Gateway transmission additions: the Mona-Oquirrh segment of Energy Gateway Central by June 2013, and the Sigurd-Red Butte segment by June 2014.

Modeling Approach Overview

The LOLP modeling approach entailed adding incremental reliability resource capacity to a starting point resource portfolio to reach increasingly higher target PRM levels. Loads and resources reflect those of the September 21, 2010 preliminary capacity load & resource balance, as presented at the October 5, 2010 IRP public input meeting.[50] This balance uses the annual system coincident peak load forecast prepared in September 2010 for use in the Company's 2011 business plan. The starting PRM level was 8.3 percent, which covers system operating reserve requirements (contingency and regulating reserves). Reliability resource capacity was then added to reach planning reserve margin levels of approximately 10 percent, 12 percent, 15 percent, and 18 percent. PacifiCorp conducted stochastic Monte Carlo simulations for each of the five resource portfolios built to achieve the target PRMs. The stochastic simulations account for Western Electricity Coordinating Council (WECC) operating reserve obligations plus incremental operating reserves for existing and forecasted wind additions as of year-end 2013. PacifiCorp then extracted LOLH and associated LOLP statistics from the portfolio simulations to characterize the reliability impacts of the incremental reliability resource capacity.

Planning Reserve Margin Build-Up

PacifiCorp used an intercooled aeroderivative simple-cycle combustion turbine (IC aero SCCT) as the reliability resource for the loss of load study. Starting from a portfolio with approximately a zero PRM, IC aero SCCT capacity blocks were added to PacifiCorp's East and West Balancing Authority Areas—PacifiCorp East (PACE) and PacifiCorp West (PACW)—until reaching the desired PRM. The capacity build-up includes 77 MW of non-owned reserves held for other parties located in PacifiCorp's Balancing Authority Areas, and accounts for the treatment of dispatchable load control (Class 1 DSM), interruptible load contracts, and purchases in the

[49] Calculating a probability using LOLH is a variant of the Loss of Load Expectation (LOLE) statistic.

[50] The preliminary 2011 IRP capacity load and resource balance is reported on page 45 of the meeting presentation, which can be downloaded at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/PacifiCorp_2011IRP_PIM4_10-05-10.pdf

calculation of the reserve margin (See Chapter 5 for more details). Additionally, since the capacity balance uses a load forecast before energy efficiency (Class 2 DSM) load reductions are applied (the "pre-DSM" load forecast), PacifiCorp included a reserve credit for the incremental 307 MW of Class 2 DSM capacity added by 2014. Modeled SCCT units were sized as follows by Balancing Authority Area:

- PacifiCorp East Units - 93 MW (1 unit), 186 MW (2 Units), 279 MW (3 Units)
- PacifiCorp West Units - 102 MW (1 unit), 205 MW (2 Units), 307 MW (3 Units)

Regarding resource placement, PacifiCorp added SCCT capacity to transmission areas as dictated by PRM needs, with most resources placed in the West Main ("West Units") and Utah North ("East Units") transmission areas. Table J.1 shows the megawatt capacity added to reach the target PRM levels. Since capacity is added in blocks, the resulting PRM levels vary from the original target levels.

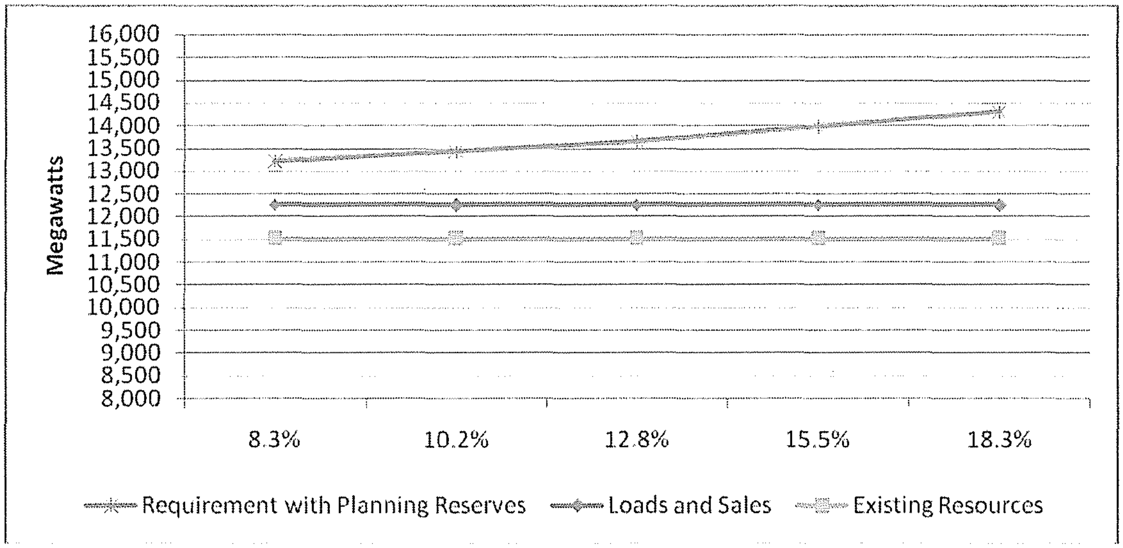
Table J.1 – Resource Capacity Additions Needed to Reach PRM Target Levels

	Planning Reserve Margin Level				
Resource	**8.3%**	**10.2%**	**12.8%**	**15.5%**	**18.3%**
East 3 Unit	837	1,116	1,116	1,395	1,674
East 2 Unit	186	0	186	0	0
East 1 Unit	0	0	0	93	0
Goshen	186	186	186	186	186
West 3 Unit	0	0	307	307	307
West 2 Unit	0	205	0	0	0
West 1 Unit	102	0	0	102	205
Walla Walla	102	102	102	102	102
Total IC Aero SCCT Capacity	**1,413**	**1,609**	**1,897**	**2,185**	**2,474**
DSM with Reserve Credit	**332**	**338**	**344**	**353**	**362**
Total Capacity Added*	**1,745**	**1,947**	**2,241**	**2,539**	**2,836**

* Excludes non-owned reserves held for other parties within PacifiCorp's service territory.

Figure J.1 shows the relative magnitude of existing resources, the load obligation plus sales, and resources with incremental reserves required to reach the target PRM.

Figure J.1 – Existing Resources, Loads & Sales, and Resources with Reserve Requirements



Monte Carlo Production Cost Simulation

For the loss of load study, the PaR model is configured to conduct 100 Monte Carlo simulation runs. During model execution, PaR makes time-path-dependent Monte Carlo draws for each stochastic variable. The stochastic variables include regional loads, unit outages, hydro availability, commodity natural gas prices, and wholesale electricity prices. In the case of natural gas prices, electricity prices, and regional loads, PaR applies Monte Carlo draws on a daily basis. Figures 2 through 9 show a sample of first-of-month daily loads by transmission area resulting from the Monte Carlo draws. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

Twelve representative weeks for each month, including the July system peak week, were modeled on an hourly basis. This representative-week approach reduces the model run-time requirements while ensuring that unit dispatch during the critical capacity planning periods is captured in the system simulations. Since only one year was simulated, the stochastic model's long-term stochastic parameters were turned off.

Figure J.2 – Utah North Load Area

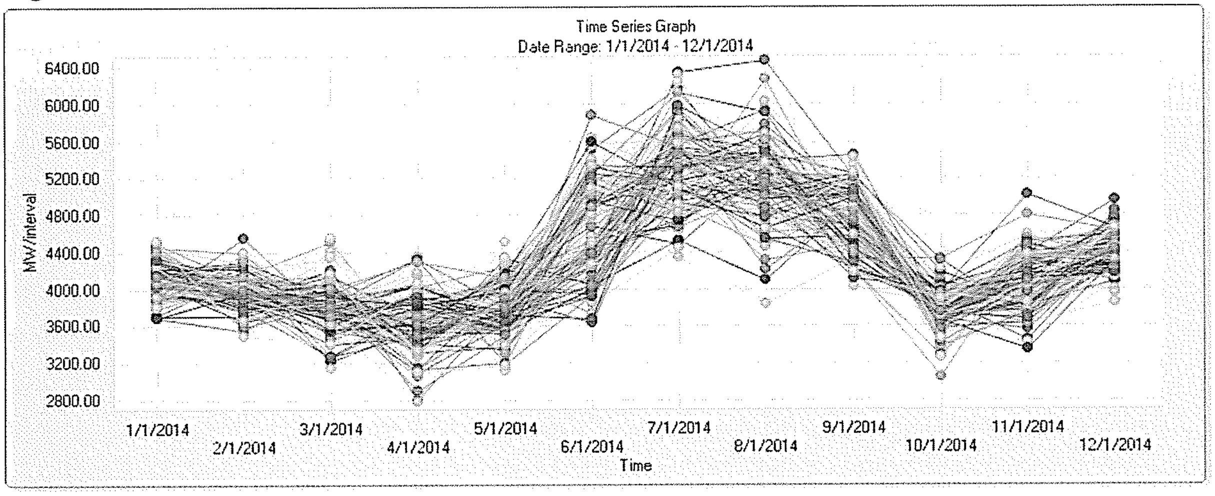


Figure J.3 – Utah South Load Area

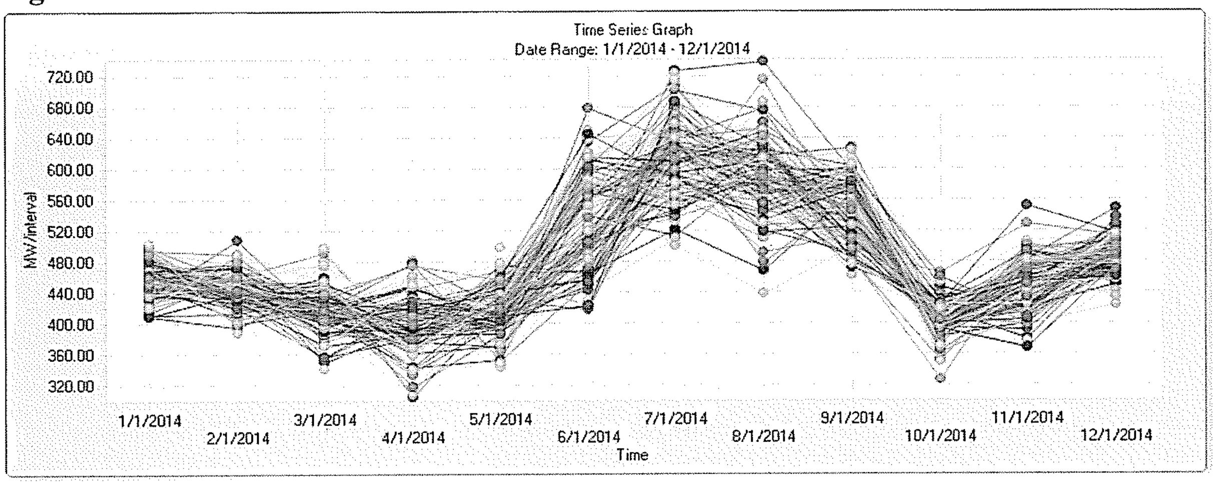


Figure J.4 – Walla Walla, Washington Load Area

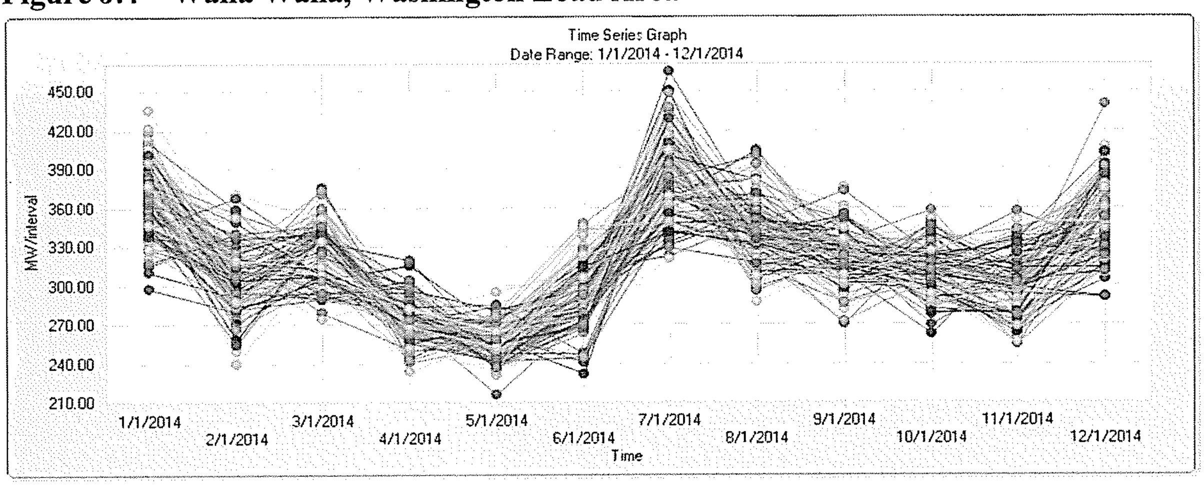


Figure J.5 – West Main (Oregon, Northern California) Load Area

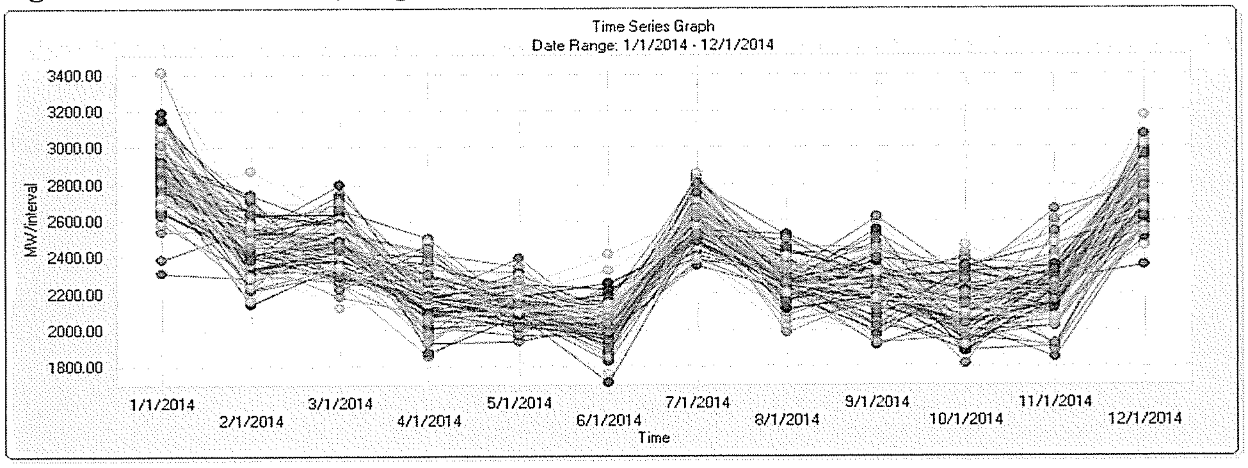


Figure J.6 – Yakima Load Area

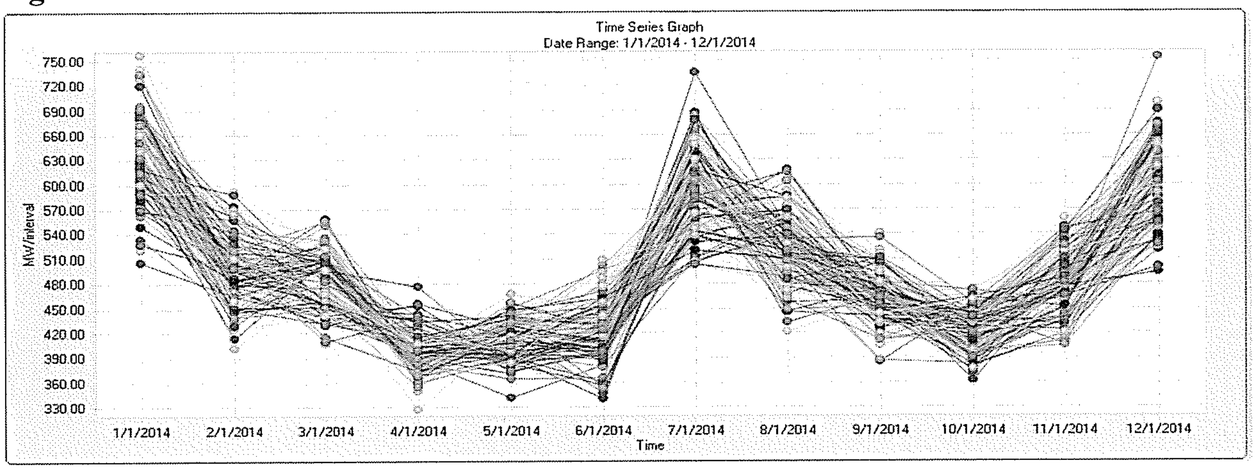


Figure J.7 – Goshen Idaho Load Area

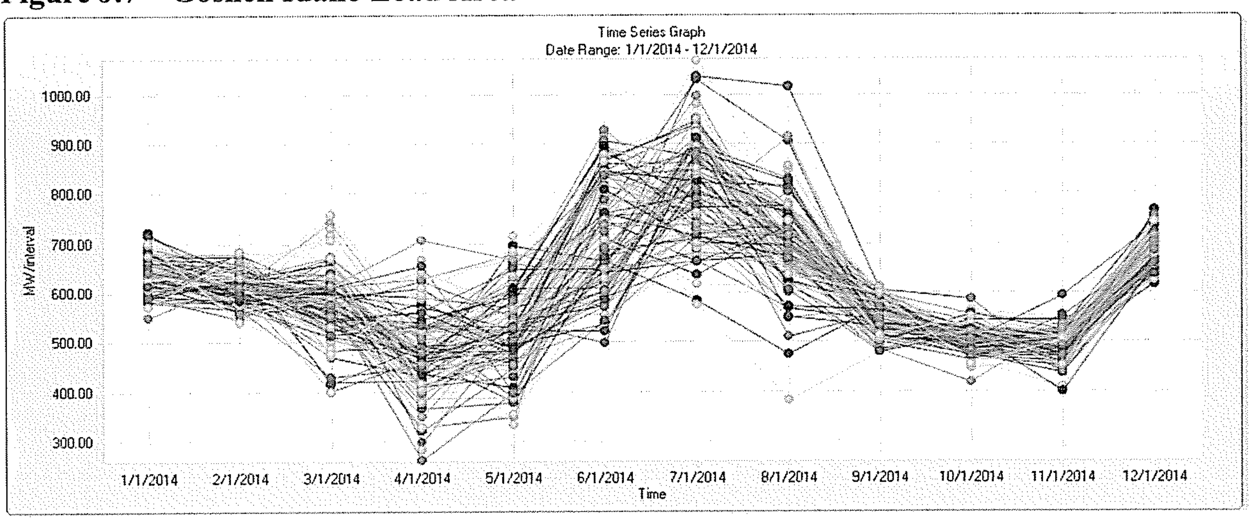


Figure J.8 – Northeast Wyoming Load Area

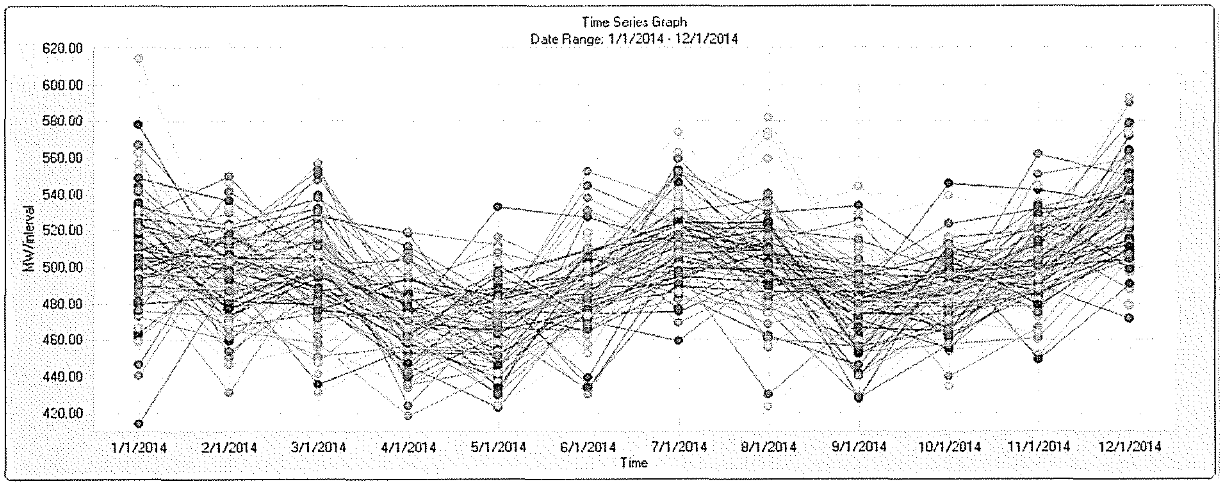
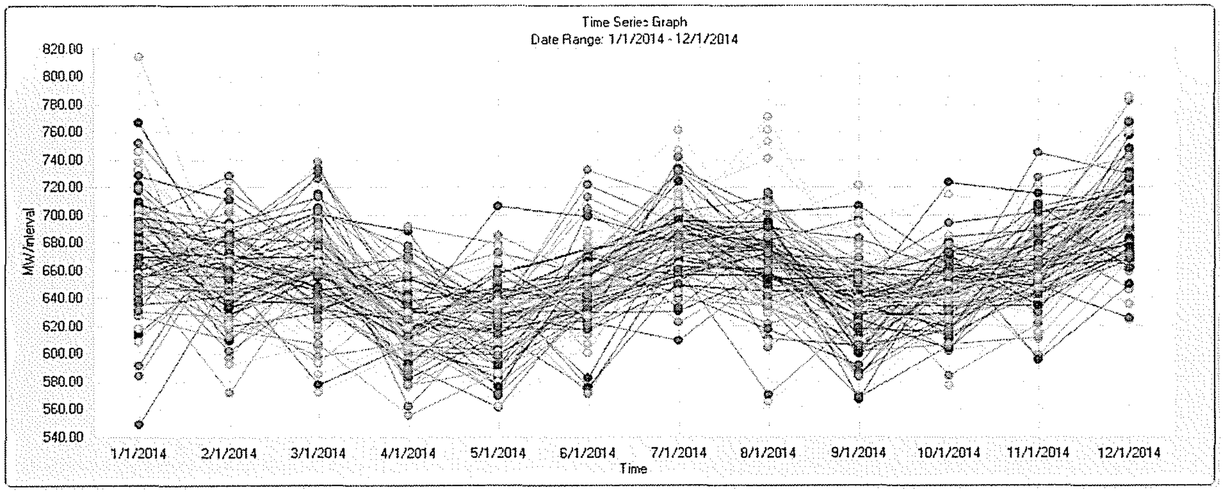


Figure J.9 – Southwest Wyoming Load Area



Modeling Operating Reserves

As part of the WECC, PacifiCorp is currently required to maintain at least 5 percent and 7 percent operating reserve margins on hydro and thermal load-serving resources, respectively. The Northwest Power Pool (NWPP) also requires a 5 percent operating reserve margin on wind. In the PaR model, operating reserves are modeled as a function of load. The maximum reserve amount that each generating unit can carry is specified in the model. The PaR model also includes 1.6 percent of loads to cover the WECC regulating reserves requirements. The operating reserve percentages, exclusive of wind, equate to 8.6 percent for the East Balancing Area and 8.1 percent for the West Balancing Area. These operating reserves are split into, roughly, 60-percent spinning and 40-percent non-spinning reserves to comply with WECC spinning and non-spinning reserve requirements.[51] An additional 14 percent incremental operating reserve

[51] At least half of the operating reserves must be Spinning Reserve. Spinning reserve is the margin of generating capacity available to replace lost capacity and provide the regulating margin to follow load; spinning capacity must

requirement is applied against nameplate wind capacity (211 MW) to cover incremental operating reserves for wind as determined by PacifiCorp's 2010 wind integration study.

The operating reserve modeling approach does not address the impact of resource type (i.e., hydro, wind, or thermal) in determining required operating reserves. Operating reserves count toward the PRM, but the required percentages for the Balancing Authority Areas (8.6 percent and 8.1 percent) stay constant regardless of resource mix.

All Balancing Authorities within the Northwest Power Pool are also required to participate in the Contingency Reserve Sharing Program. This program provides 60-minute recovery assistance following the loss of a generating resource or transmission path, or failure of a generating unit to start up or increase output. This assistance is provided after the Balancing Authority uses up its Contingency Reserve Obligation (i.e., 7 percent of load served by thermal resources; 5 percent of load served by hydro reserves). The reserve sharing program provides a benefit to the utility by covering the first hour of an outage. For recording LOLH and calculating LOLP, the stochastic simulation should omit the first hour of a forced outage event in order to capture reserve sharing benefits. Implementing this functionality in the PaR model requires that a "shadow" station be assigned to each unit with a capacity equal to the unit MW rating and energy equal to the full load output. The shadow station is called upon in the event of a unit outage, thereby contributing emergency generation for one hour during the outage period. (The PaR model would determine that hour based on the marginal energy cost during the outage period.)

This modeling approach was judged to be too complex to implement and validate in time for use in the 2011 IRP. However, this approach was implemented for a loss of load study conducted by the PaR model vendor, Ventyx LLC, for Public Service Company of Colorado. The impact to the PRM of modeling reserve sharing rules of the Rocky Mountain Reserve Group (RMRG) was a reduction of 1.5 percentage points.[52] While the RMRG reserve sharing rules provide for up to two hours of contingency reserve assistance as opposed to the one hour for the Northwest Power Pool's program, the RMRG rules are more restrictive in other respects. For example, reserve support is targeted for units at least 200 MW in size, is provided only to the unit with the largest capacity in the event that two or more units experience simultaneous outages, covers only one outage event per month, and covers less than the full unit capacity due to a smaller pool of member reserves available. Given these offsetting limitations, PacifiCorp assumes that a PRM reduction of 1.5 percentage points is a reasonable proxy for the NWPP's reserve sharing benefit.

Study Results

Figure J.10 reports the LOLH counts for the five PRM levels modeled, while Figure J.11 reports the resulting LOLE index values (the stochastic average for the 100 Monte Carlo iterations).

be synchronized to the system and ready to provide power instantaneously. Non-spinning reserve is generating capacity that is not synchronized to the system but can be available within a few hours – although some capacity may be ready immediately.

[52] The loss of load report is available at:
http://www.xcelenergy.com/SiteCollectionDocuments/docs/CRPReserveMarginStudy.pdf

Fitted curves highlight the smooth relationship between the reliability statistics and the PRM level.

Figure J.12 reports the total fixed cost of meeting each PRM level based on the incremental IC aero SCCT resource capacity required. The per-unit fixed cost is approximately $191/kW-year, which is grossed up to account for a 2.7 percent expected forced outage rate. Each percentage point increase in the PRM translates into an incremental fixed cost of about $42 million.

Figure J.10 – System LOLH by Planning Reserve Margin Level

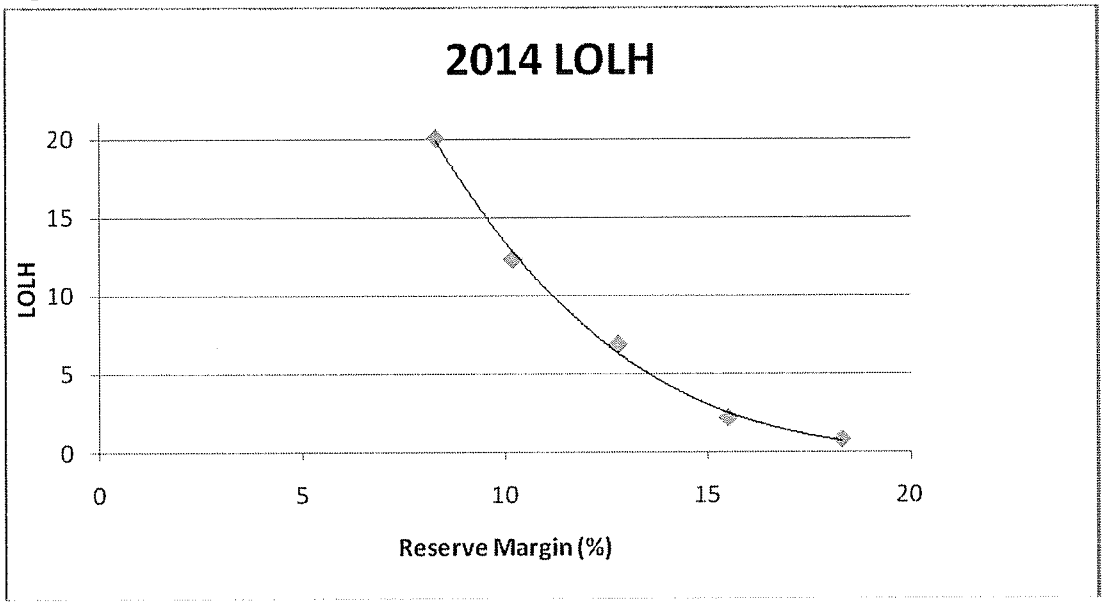


Figure J.11 – System LOLP Index by Planning Reserve Margin Level

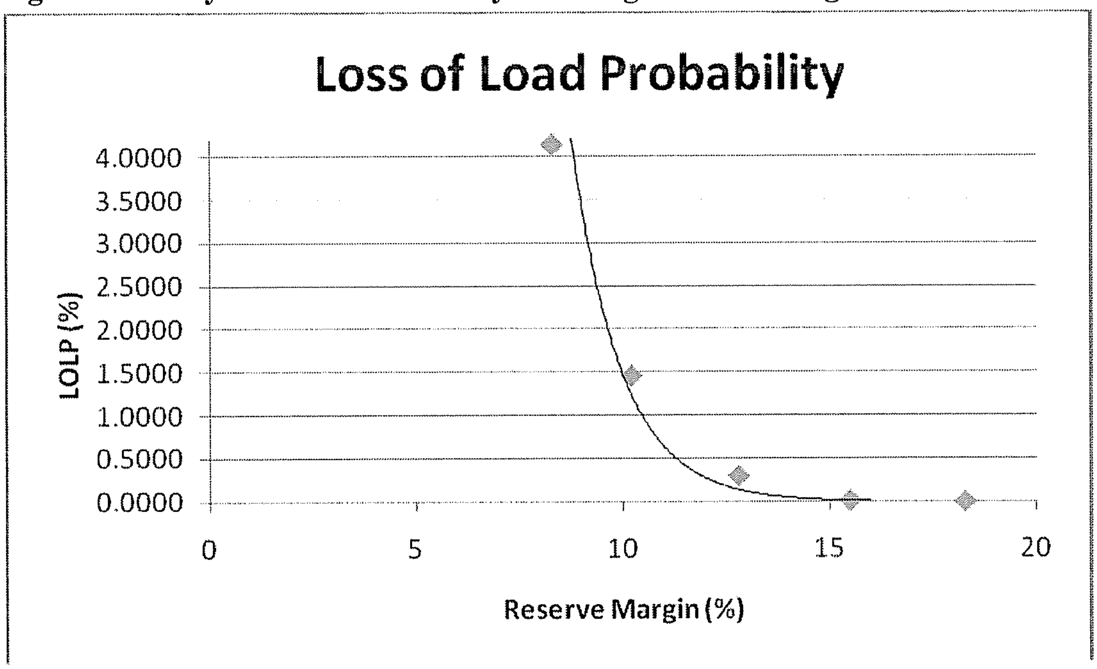
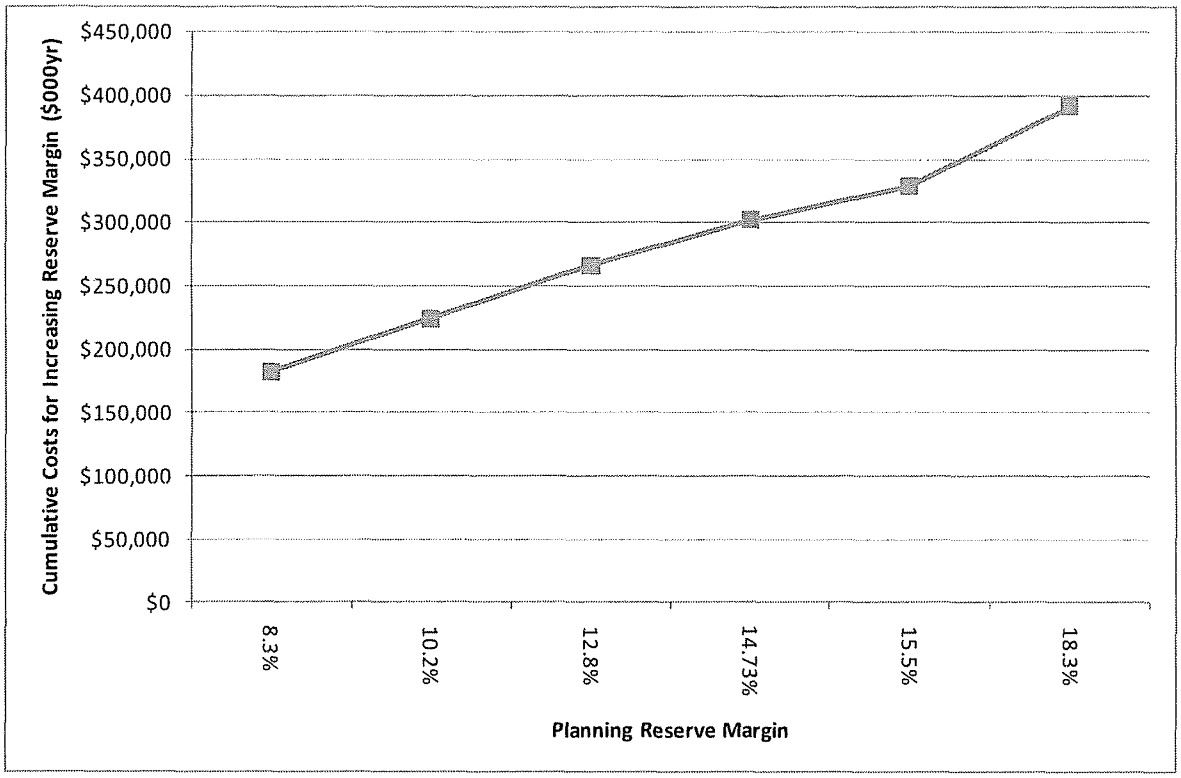


Figure J.12 – Reliability Resource Fixed Costs Associated with Meeting PRM Levels

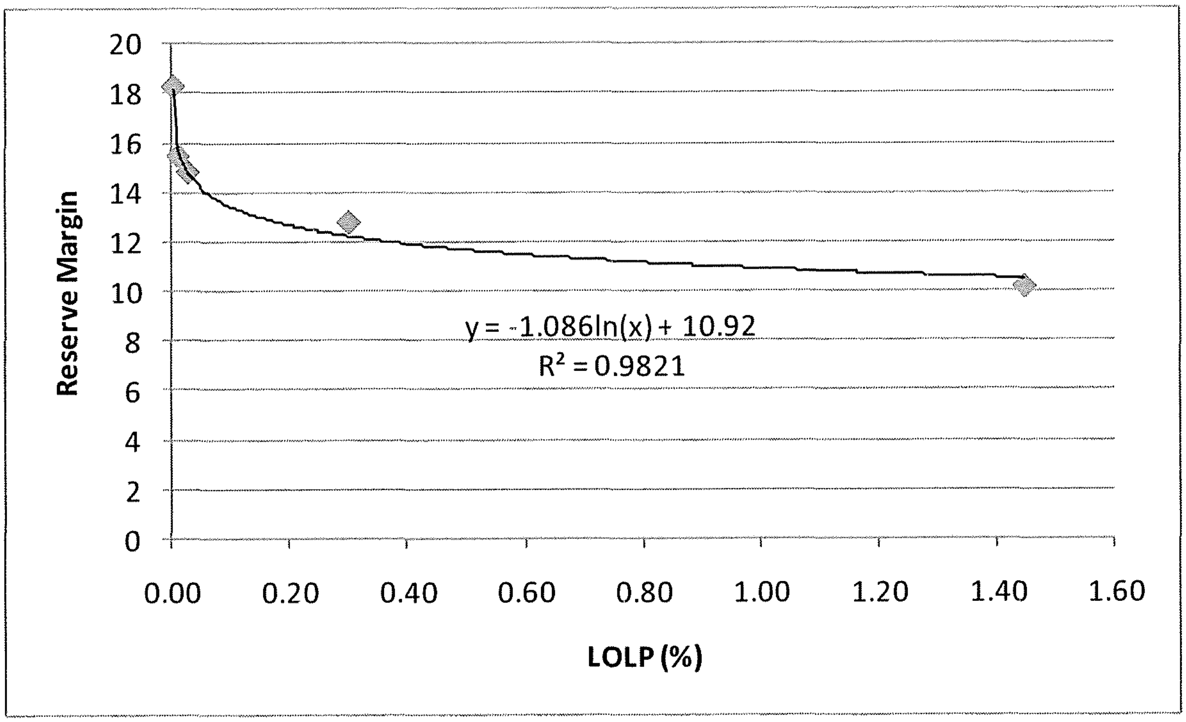


SELECTION OF A LOLP RELIABILITY TARGET

Traditionally, the long-term reliability planning standard has been a one-day in ten year loss of load criterion: 24 hours / (8760 hours x 10 years) = 0.027 percent. PacifiCorp has thus adopted this standard for determination of its PRM for IRP portfolio development.[53] Using a logarithmic functional form and regressing the PRM levels against the LOLE values, yielded a PRM of 14.8 percent to achieve a one-day in ten year loss of load (Figure J.13).

[53] Reliance on a one-in-ten loss of load criterion is being bolstered at the Federal level. The Federal Energy Regulatory Commission issued a Notice of Proposed Rulemaking in October 2010 approving a regional resource adequacy standard for Reliability*First* Corporation (RFC) based on a one-in-ten loss of load criterion. RFC is one of the nine North American Electric Reliability Corporation's electricity reliability councils, consisting of the former Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN).

Figure J.13 – Relationship between Reserve Margin and LOLP



Capacity Planning Reserve Margin Determination

As noted previously, the loss of load study does not incorporate the benefit of the Northwest Power Pool reserve sharing program. As a result, the 14.8 percent PRM requires a downward adjustment. Applying the 1.5 percent RMRG reserve sharing impact estimated by Ventyx for Public Service Company of Colorado results in an adjusted PRM of 13.3 percent. Rounding to 13 percent yields the PRM that PacifiCorp selected for its 2011 IRP portfolio development.

Conclusion

Based on the loss of load study and an out-of-model planning reserve margin adjustment to reflect reliability benefits from the Northwest Power Pool's reserve sharing program, PacifiCorp selected a 13% PRM for 2011 IRP portfolio development. PacifiCorp's previous PRM was 12 percent. This study incorporated a one-year snapshot of the transmission topology and loads & resources situation, targeting 2014 as the representative study year. Since the study focused on the PRM needed to meet firm load and sales obligations, it did not incorporate the reliability benefits of accessing off-system generation with non-firm transmission capacity.

PacifiCorp evaluated the reliability impact of different resource mixes using LOLP and Energy Not Served measures as part of its portfolio evaluation process.

APPENDIX K – HYDROELECTRIC CAPACITY ACCOUNTING

Introduction

The Utah Commission, in its 2008 IRP acknowledgment order, directed the Company to revisit its approach for estimating the capacity contribution of hydroelectric facilities for load & resource balance development purposes. Both the Utah Division of Public Utilities and Office of Consumer Services specifically recommended in their written comments on the 2008 IRP that the Company continue to investigate the hydro capacity accounting methodology adopted for regional resource adequacy reporting purposes by the Pacific Northwest Resource Adequacy Forum, an organization sponsored by the Northwest Power and Conservation Council (NWPCC). This accounting methodology extends the one-hour sustained peaking period to the six highest load hours over three consecutive days of highest demand. The methodology was originally adopted in 2008, and continues to be investigated and refined.

In this appendix, the Company first describes what hydro facilities are eligible for providing sustained hydro peaking capability under an 18-hour standard, and then reports its estimates of the 18-hour sustained hydro capability for the eligible facilities. The Company then discusses the applicability of this standard to PacifiCorp's hydroelectric system.

Eligible Sustained Peaking Hydro Facilities

PacifiCorp evaluated its hydro resource portfolio according to the definitions and methodologies outlined by the current standards established by the Pacific Northwest Resource Adequacy Forum. The following PacifiCorp hydroelectric facilities apply with regard to supporting sustained capacity for the Northwest:

Lewis River

- Swift-1
- Swift-2
- Yale

Other hydro facilities owned and operated by PacifiCorp that provide limited peaking

- JC Boyle
- Copco-1
- Copco -2
- Lemolo -1
- Lemolo- 2
- Toketee
- Slide Creek
- Oneida

- Cutler

This second group of hydro facilities was determined to be ineligible for providing sustained peaking capability as defined by the Pacific Northwest Resource Adequacy Forum. For example, they lack sufficient storage for sustained peaking and are constrained in their dispatch by minimal inflow during the peak load period (July), have ramping regulations imposed within the operating license, restrictive minimum flow regulation and stage change downstream of the project, irrigation priority, and fisheries/recreation requirements. Only the Lewis River facilities listed above (Swift-1, Swift-2, and Yale) meet the criteria for providing 18-hour sustained peaking capability without extraordinary actions taken regarding adaptive policy decisions or waivers by the various governing agencies and primary stakeholders of the project output.

Sustained Hydro Peaking Capability for Lewis River Facilities

During the July peak load period, the Swift and Yale reservoirs are maintained near full pool elevation in support of recreation. Historical median flow into the Swift reservoir in July is 1245-cubic feet per second (cfs). The median natural accretion between Swift and Yale reservoirs is 198 cfs. The median natural accretion between Yale and Merwin reservoirs is 198 cfs. Minimum flow below the re-regulating facility downstream of Swift and Yale, varies during the month of July from 2,300 cfs in the first ten days, 1900 cfs in the second ten days, and 1,500 cfs in the last ten days of the month. From July 31st to mid October, the minimum flow is 1,200 cfs. In a median water year, Swift and Yale reservoirs operate in the upper eight feet of the reservoir 100 percent of the time in July. Over a 15-year consecutive period, Swift and Yale reservoirs operate in the upper eight feet of the reservoir 93 percent of the time in July. In the upper eight feet of the reservoirs, Swift 1 and 2 and Yale are capable of 344 MW and 134 MW, respectively. The maximum sustained peak capacity for Swift 1 and 2 combined is 210 MW. At Yale, the maximum sustained peak capacity is 95 megawatts. The total combined sustained peak capacity is therefore 304 MW. The difference between the one-hour sustained peaking capacity and 18-hour sustained peaking capacity is a reduction of 164 MW as indicated in Table

Table K.1 – Peaking Capability Comparison for Lewis River Hydro Facilities

Unit	One-hour Sustained Peaking Capability (MW)	18-hour Sustained Peaking Capability Capacity (MW)	Difference (MW)
Swift 1 and 2	319	210	(109)
Yale	150	95	(55)
TOTAL	**469**	**305**	**(164)**

These estimates were determined assuming the critical event occurs in the first ten days of July when the minimum stream flow requirement is the highest. Given the median inflows and assuming the same 18-hour sustained peaking period, the available peak flow for Swift 1 and 2 is 5,000 cfs, whereas the peak flow for Yale is 5,800 cfs. The above stated sustained capacity pertains to these peak period flows. Under peak operation, reservoir levels remain approximately constant as normally required to support recreation.

Applicability of an 18-hour Sustained Peaking Capability Standard for PacifiCorp

The Pacific Northwest Resource Adequacy Forum's 18-hour sustained peaking period standard is intended as a broad regional capacity planning guideline. The issue is whether it makes sense to adopt for PacifiCorp based on its hydro licensing provisions and operational protocols and practices. In practice, the Company would not adhere to reservoir level compliance or constant stream flow regulation below Merwin if there was an emergency need for generation to support critical load. In a real world situation, PacifiCorp would generate to maximum capacity of the units and make the necessary public announcements unless instructed to provide the sustained capacity per a revised peaking period definition enforced by the Western Electric Coordinating Council or Northwest Power Pool.

Conclusion

The Company has the ability to operate outside the normal boundaries of the operating license given emergency conditions, which means that the 18-hour sustained peaking standard would not be relevant for peak capacity planning as it relates to PacifiCorp's hydro system. Additionally, the choice of the length of the sustained peaking period has minimal consequences for capacity position reporting given that the sustained peaking period must be consistently applied to both hydro capacity and peak loads.

It is also important to note that the NWPPC characterizes the Resource Adequacy Forum's capacity adequacy standard as being useful for informing hydro utilities' resource planning efforts, and not as a methodology that should be adopted in lieu of the utilities' own planning criteria and methodologies.

APPENDIX L – PLANT WATER CONSUMPTION

The information provide in this appendix is for PacifiCorp owned plants. Total water consumption and generation includes all owners for jointly-owned facilities

Table L.1 – Plant Water Consumption with Acre-Feet Per Year

			Acre-Feet Per Year					MWhs Per Year					
PLANT NAME	Discharge Permit?	Consumption net of Discharge?	2007	2008	2009	2010	Average	2007	2008	2009	2010	Gals/ MWH	GPM/ MWh
Carbon	Yes	No	2,380	2,199	2,349	2,193	2,280	1,339,343	1,204,982	1,211,875	1,296,004	588	9.8
Chehalis*	Yes	Yes					-			1,747,252	1,288,256	-	0.0
Currant Creek*	Zero Discharge	Does not apply	116	82	108	83	97	3,605,071	2,799,585	2,464,463	2,536,660	11.1	0.2
Dave Johnston	Yes	No	7,872	7,746	6,983	6,604	7,301	5,696,860	5,638,806	5,017,796	4,699,767	452	7.5
Gadsby**	Yes	No	778	426	680	893	694	633,049	482,596	605,817	359,404	435	7.2
Hunter	Zero Discharge	Does not apply	19,157	19,380	19,300	19,200	19,259	9,600,295	10,246,965	9,438,683	8,785,827	659	11.0
Huntington	Zero Discharge	Does not apply	11,737	11,385	10,922	9,566	10,903	7,127,084	7,148,850	6,753,764	6,107,379	524	8.7
Jim Bridger	Zero Discharge	Does not apply	25,616	27,322	25,361	24,076	25,594	15,119,379	15,303,508	15,188,184	14,828,906	552	9.2
Lakeside***	Yes	Yes	0	1,821	1,287	1,533	1,160	0	2,861,722	2,099,109	2,537,046	202	3.4
Naughton	Yes	No	9,948	10,992	10,846	0	7,947	5,210,618	5,114,409	4,752,632	5,339,603	687	11.4
Wyodak*	Zero Discharge	Does not apply	405	446	365	396.00	403	2,862,771	2,811,590	2,716,055	2,565,341	47	0.8
TOTAL			**78,009**	**81,799**	**78,201**	**64,543**	**79,336**	**51,194,470**	**53,613,013**	**51,995,630**	**50,344,193**	**476**	**7.9**

* Equipped with air cooled condenser

**Mix of both rankine steam units and peaking gas turbines

*** First full year of water consumption occurred in 2008

1 acre-foot of water is equivalent to: 325,851 Gallons or 43,560 Cubic Feet

Table L.2 – Plant Water Consumption by State

UTAH PLANTS			
PLANT NAME	**2007**	**2008**	**2009**
Hunter	19,157	19,380	19,300
Huntington	11,737	11,385	10,922
Carbon	2,380	2,199	2,349
Currant Creek	116	82	108
Lakeside	-	1,821	1,287
Gadsby	778	426	680
TOTAL	**34,168**	**35,293**	**34,646**

Percent of total water consumption = 43.7%

WYOMING PLANTS			
PLANT NAME	**2007**	**2008**	**2009**
Naughton	9,948	10,992	10,846
Jim Bridger	25,616	27,322	25,361
Wyodak	405	446	365
Dave Johnston	7,872	7,746	6,983
TOTAL	**43,841**	**46,506**	**43,555**

Percent of total water consumption = 56.3%

Table L.3 – Plant Water Consumption by Fuel Type

COAL FIRED PLANTS			
PLANT NAME	**2007**	**2008**	**2009**
Hunter	19,157	19,380	19,300
Huntington	11,737	11,385	10,922
Carbon	2,380	2,199	2,349
Naughton	9,948	10,992	10,846
Jim Bridger	25,616	27,322	25,361
Wyodak	405	446	365
Dave Johnston	7,872	7,746	6,983
TOTAL	**77,115**	**79,470**	**76,126**

Generation Capacity (MW)	**Ac-ft/MW**
1320	14.6
895	12.7
175	13.2
700	15.1
2120	12.3
335	1.2
762	9.9
Average	**11.3**

Percent of total water consumption = 97.8%

NATURAL GAS FIRED PLANTS					
PLANT NAME	2007	2008	2009	Generation Capacity (MW)	Ac-ft/MW
Currant Creek	116	82	108	523	0.2
Lakeside	-	1,821	1,287	575	2.7
Gadsby	778	426	680	235	2.7
TOTAL	**894**	**2,329**	**2,075**	**Average**	**1.9**

Percent of total water consumption = 2.2%

Table L.4 – Plant Water Consumption for Plants Located in the Upper Colorado River Basin

PLANT NAME	2007	2008	2009
Hunter	19,157	19,380	19,300
Huntington	11,737	11,385	10,922
Carbon	2,380	2,199	2,349
Naughton	9,948	10,992	10,846
Jim Bridger	25,616	27,322	25,361
TOTAL	**68,838**	**71,278**	**68,778**

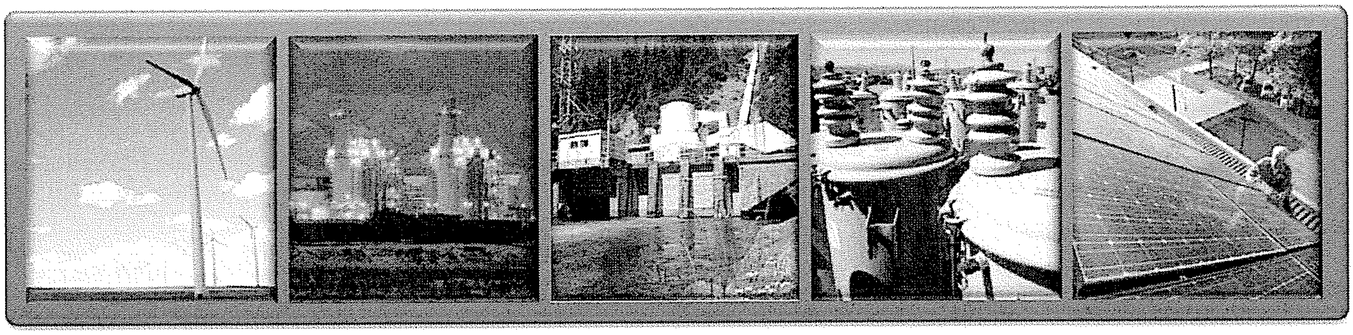
Percent of total water consumption = 87.8%

PACIFICORP

Rocky Mountain Power
Pacific Power
PacifiCorp Energy

2011 Integrated Resource Plan

Volume I



Let's turn the answers on.

March 31, 2011

This 2011 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

For more information, contact:
PacifiCorp
IRP Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
(503) 813-5245
irp@pacificorp.com
http://www.pacificorp.com

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Cover Photos (Left to Right):
Wind: *McFadden Ridge I*
Thermal-Gas: *Lake Side Power Plant*
Hydroelectric: *Lemolo 1 on North Umpqua River*
Transmission: *Distribution Transformers*
Solar: *Salt Palace Convention Center Photovoltaic Solar Project*
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CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp's 2011 Integrated Resource Plan (2011 IRP), representing the 11^{th} plan submitted to state regulatory commissions, presents a framework of future actions to ensure PacifiCorp continues to provide reliable, reasonable-cost service with manageable risks to its customers. It was developed with participation from numerous public stakeholders, including regulatory staff, advocacy groups, and other interested parties.

The key elements of the 2011 IRP include (1) a finding of resource need, focusing on the 10-year period 2011-2020, (2) the preferred portfolio of incremental supply-side and demand-side resources to meet this need, and (3) resource and transmission action plans that identify the steps the Company will take during the next two to four years to implement the plan. The process and outcome of the IRP—the preferred portfolio and action plans—meet applicable state IRP standards and guidelines. PacifiCorp continues to plan on a system-wide basis while accommodating state resource acquisition mandates and policies.

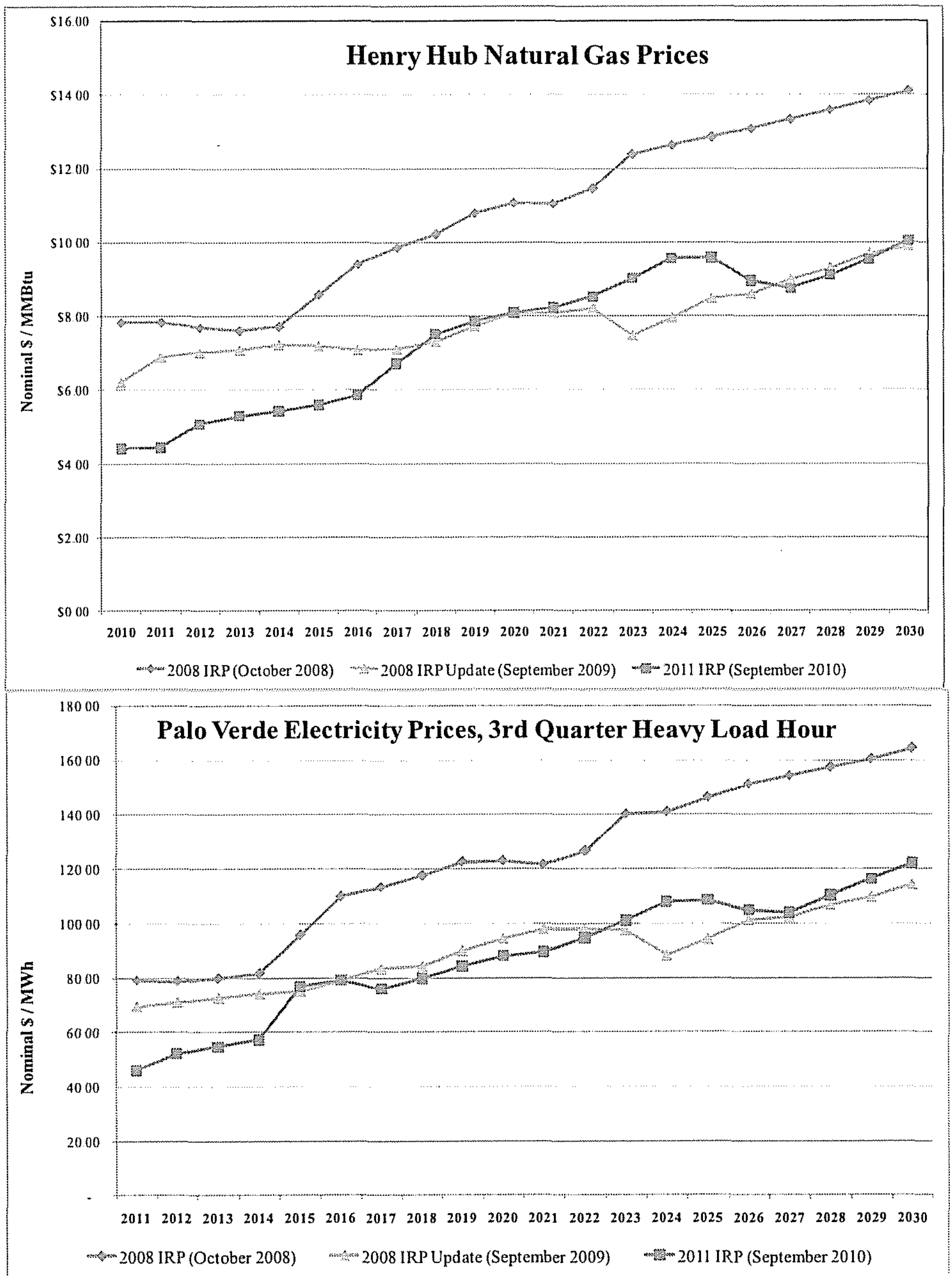
Development of the 2011 IRP involved balanced consideration of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. The resulting preferred portfolio reflects a significant increase in energy efficiency relative to prior IRPs, new gas-fired combined-cycle combustion turbines, and continuous annual renewable resource additions beginning in 2018, assumed to be wind for planning purposes. Firm market purchases also are relied upon, particularly through 2015, taking advantage of favorable market prices.

As an evolving process, the IRP incorporates current information and reflects continuous improvements in system modeling capability required to address new issues and an expanding analytical scope. For example, PacifiCorp recently implemented enhancements to its capacity expansion optimization tool, *System Optimizer*, for tracking carbon dioxide emissions and renewable energy production between load areas. Likewise, the preferred portfolio and action plans are not static products reflecting resource acquisition commitments, but rather represent a flexible framework for considering resource acquisition paths that may vary as market and regulatory conditions change. The preferred portfolio and action plans are augmented by a resource acquisition path analysis informed by extensive portfolio scenario modeling. As noted in this and prior IRPs, specific resource acquisition decisions stem from PacifiCorp's procurement process as supported by the IRP and business planning processes, as well as compliance with then-current laws and regulatory rules and orders.

Key drivers guiding the 2011 IRP process and its outcome include the following:

- Decreases in projected natural gas and wholesale electricity prices relative to the forecasts prepared in 2008 and 2009, favor natural gas fueled resources and market purchases. These price forecast decreases, shown graphically in Figure ES.1, are caused mainly by the boom in nonconventional domestic natural gas discoveries and a robust long-term supply outlook.

Figure ES.1 – Price Forecast Comparisons for Recent IRPs



- Loss of momentum in federal efforts to develop comprehensive federal energy and climate change compliance requirements contribute to continued uncertainty regarding the long-term investment climate for clean energy technologies. Nevertheless, public and legislative support for clean energy policies at the state level remains robust.
- Continued aggressive efforts by the U.S. Environmental Protection Agency to regulate electric utility plant emissions, including greenhouse gases, criteria pollutants, and other emissions.
- Expectations for a more favorable economic environment than assumed in 2009 accompanied by load growth in such areas as data centers and natural resource extraction.
- Progress and challenges in planning for, permitting, and building the Energy Gateway transmission project, coupled with the potential for state-specific cost recovery issues.

- 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. (PacifiCorp treated this resource as an option in all scenarios analyzed, and was selected by System Optimizer in every scenario.)

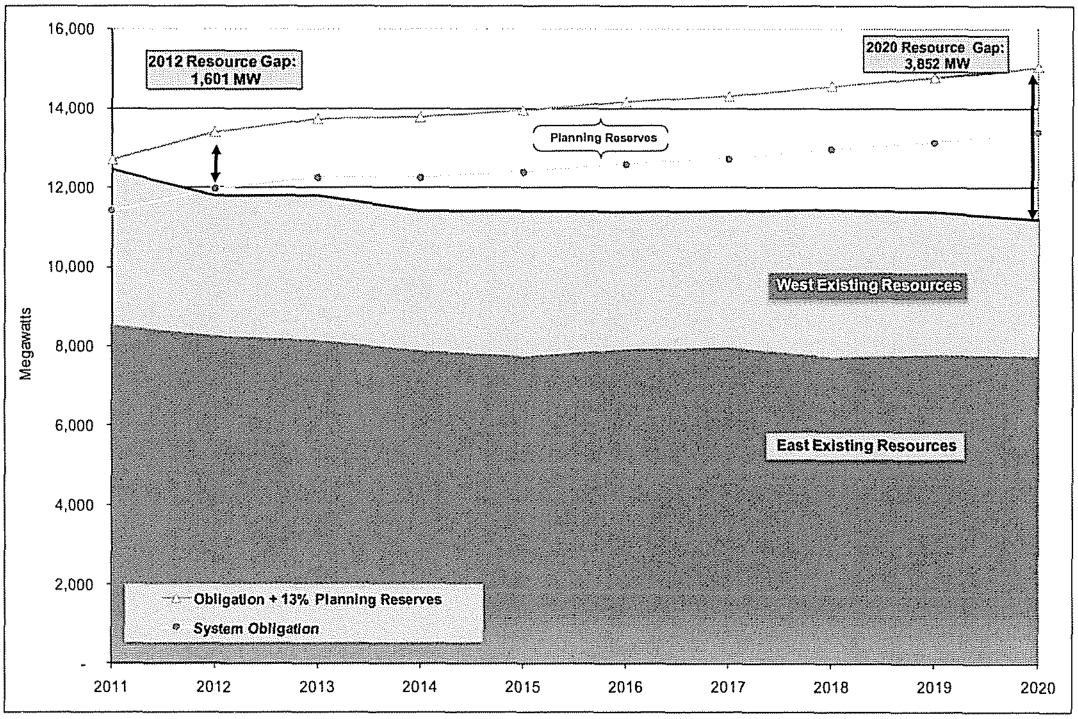
Resource Need

PacifiCorp is expected to need 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. Resource need is determined by developing a capacity load and resource balance that considers the coincident system peak load hour capacity contribution of existing resources, forecasted loads and sales, and reserve requirements. Table ES.1 shows the Company's annual capacity position for 2011 through 2020, while Figure ES.2 graphically highlights the capacity resource gap and contribution of currently owned and contracted east and west-side resources. Without new resources, the system experiences a capacity deficit of 326 MW in 2011 and 3,852 MW by 2020. Underlying the capacity position is system annual peak load growth of 2.1 percent on a compounded average annual basis (prior to forecasted load reductions from energy efficiency). On an energy basis, PacifiCorp expects system-wide average load growth of 1.8 percent per year.

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)

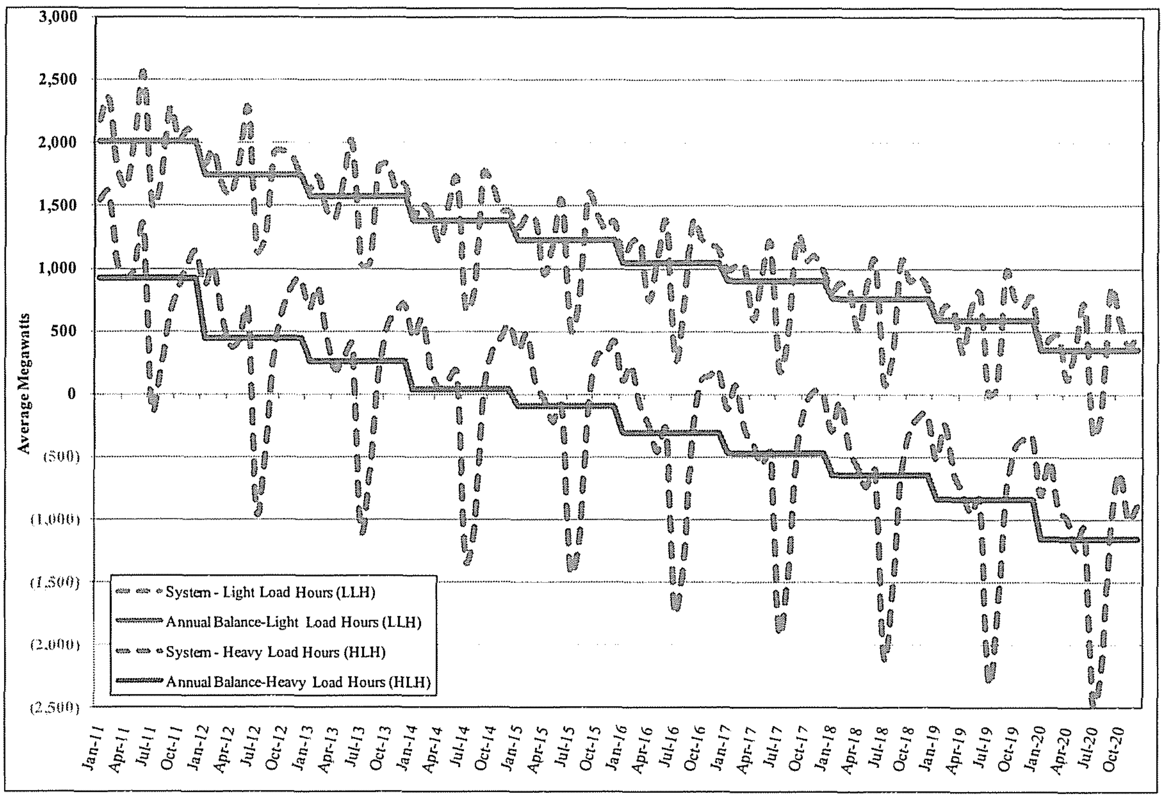
Figure ES.2 – PacifiCorp Capacity Resource Gap



For capacity expansion planning, the Company uses a 13-percent planning reserve margin applied to PacifiCorp's obligation (load plus sales obligations) less firm purchases and dispatchable load control capacity. The 13-percent planning reserve margin is supported by a stochastic loss of load probability study conducted in late 2010.

On an average monthly energy basis, the system begins to experience short positions for heavy load hours[1] in 2011, while on an average annual basis, short positions occur by 2015 (Figure ES.3).

Figure ES.3 – System Average Monthly and Annual Energy Balances



Transmission Planning

PacifiCorp is obligated to plan for and meet its customers' future needs, and to manage uncertainties surrounding regulation of carbon dioxide (CO_2) emissions, other criteria pollutants, and potential new requirements for renewable resources. PacifiCorp's priority in building Energy Gateway transmission is to meet these customer needs, also recognizing its belief that energy policies will continue to push toward renewable and low-carbon resource requirements. Regardless of future policy direction, the Energy Gateway projects are well aligned with rich and diverse resources throughout the Company's service territory. Timely permitting by agencies and regulatory support is critically important to these investments materializing in time to meet PacifiCorp's need to serve load.

[1] Heavy load hours constitute the daily time block of 16 hours, Hour-Ending 7 am – 10 pm, for Monday through Saturday, excluding NERC-observed holidays.

The cycle time to add significant new transmission facilities is often much longer than adding generation or securing contractual resources. Transmission additions must be integrated into regional plans before permitting and constructing the physical assets. PacifiCorp plans and builds its transmission system based on its network customers' 10-year load and resource forecasts. Per FERC guidelines, the Company is able to reserve transmission network capacity based on this 10-year forecast, but in PacifiCorp's experience, the lengthy planning, permitting and construction timeline required for significant transmission investments, as well as the typical useful life of these facilities, is well beyond 10 years. A 20-year planning horizon and ability to reserve transmission capacity to meet forecasted need over that timeframe is more consistent with the time required to plan for and build large scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

PacifiCorp's transmission network is also required to meet increasingly stringent mandatory federal reliability standards, which require infrastructure sufficient to withstand unplanned outage events. The majority of these mandatory standards are the responsibility of the transmission owner.

For this IRP, a number of Energy Gateway configurations, ranging from Gateway Central to the full Gateway expansion scenario, were investigated in the context of alternate CO_2 cost, natural gas price, and renewable portfolio standards. PacifiCorp continues to believe that proceeding with the full Gateway expansion scenario is the most prudent strategy given expected customer loads, resource diversity benefits, regulatory uncertainty, and the long lead time for adding new transmission facilities. While Energy Gateway is timed to coincide with PacifiCorp's resource needs, delays in the project due to siting and permitting challenges or other factors may result in the need to pursue alternative resource scenarios. See Chapter 10 for PacifiCorp's transmission expansion action plan, which requests regulatory acknowledgment of the Energy Gateway projects scheduled to be in-service in 2014 or sooner.

Future Resource Options and Portfolio Modeling

In line with state IRP standards and guidelines, PacifiCorp included a wide variety of resource options in portfolio modeling covering generation, demand-side management and transmission. Table ES.2 summarizes the different resource options by category included in portfolio modeling. The Company developed resource option attributes and costs reflecting updated information from project experience, public stakeholder input and consultant studies. Projected resource costs have generally decreased from the previous IRP due to the economic slow-down in 2009 and 2010. However, capital cost uncertainty for many of the generation options is high due to such factors as labor cost, commodity price, and resource demand volatility.

A 2010 resource potential study served as the basis for updated resource characterizations covering demand-side management (DSM) and distributed generation. Input on photovoltaic resource modeling assumptions from public stakeholders informed the study effort. Also in 2010, the Company commissioned a geothermal resource study that identified eight sites in the Company's service territory that potentially meet specific criteria for commercial viability.

For wind resources, PacifiCorp adopted a modeling approach that more closely aligns with Western Renewable Energy Zones and facilitates assignment of incremental transmission costs for the Energy Gateway transmission scenario analysis.

Table ES.2 – 2011 IRP Resource Options

Gas-fired, Utility Scale	Other Thermal, Utility Scale	Renewable, Utility Scale	Energy Storage, Utility Scale	Distributed Generation	Load Control (Class 1 DSM)	Energy Efficiency (Class 2 DSM)	Demand Response (Class 3 DSM)	Transmission
Cogeneration	Supercritical Pulverized Coal without CCS	Wind, 35% and 29% Capacity Factors	Advanced Battery Storage	Combined Heat & Power, Reciprocating Engine	Residential and Small Commercial Air Conditioning	Nine measure bundles grouped by cost for five states plus three measure bundles for Oregon provided by the Energy Trust of Oregon	Residential Time-of-Use	Energy Gateway Central
Aeroderivative SCCT	Supercritical pulverized coal with CCS	Geothermal, Brownfield (Dual Flash)	Hydro Pumped Storage	Combined Heat & Power, Gas Turbine	Residential Electric Water Heating	One bundle for Compact Florescent Lamps for 2011 and 2012.	Commercial Critical Peak Pricing	Energy Gateway Central plus Windstar-Populus
Intercooled Aeroderivative SCCT	Supercritical pulverized coal with retrofit CCS	Geothermal, Greenfield (Binary)	Compressed Air Energy Storage	Microturbine	Irrigation Direct Load Control		Commercial/ Industrial Demand Buyback	Energy Gateway Central plus Windstar-Populus plus Aeolus-Mona
Internal Combustion Engine	Integrated Gasification Combined Cycle with CCS	Solar, Thin Film Photovoltaic		Fuel Cell	Commercial/ Industrial Curtailment (includes distributed stand-by generation)		Commercial/ Industrial Real Time Pricing	Energy Gateway Central plus Windstar-Populus plus Aeolus-Mona plus Populus-Hemingway/Hemingway-Boardman-Cascade Crossing
SCCT Frame	Nuclear	Solar Concentrating (Thermal Trough with Gas Backup)		Commercial biomass (Anaerobic Digester)	Commercial/ Industrial Thermal Energy Storage		Mandatory Irrigation Time-of-Use	
CCCT: Wet-Cooled, Dry-Cooled, F Class, G Class, H Class		Solar Concentrating (Thermal Trough)		Rooftop Photovoltaic				
		Biomass		Solar Water Heaters				
		Hydrokinetic		Solar Attic Fans				

* CCS = Carbon Capture and Sequestration, SCCT = Simple-Cycle Combustion Turbine, CCCT = Combined-Cycle Combustion Turbine

PacifiCorp's IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios, and consists of seven phases:

- Define input scenarios for portfolio development
- Price forecast development (natural gas and wholesale electricity by market hub)
- Optimized portfolio development using PacifiCorp's *System Optimizer* capacity expansion model
- Stochastic Monte Carlo production cost simulation of each optimized portfolio
- Selection of top-performing portfolios using a two-phase screening process that incorporates stochastic portfolio cost and risk assessment measures
- Deterministic risk assessment of top-performing portfolios using System Optimizer along with the input scenarios
- Preliminary preferred portfolio selection, followed by resource acquisition risk analysis and determination of the final preferred portfolio

PacifiCorp defined 67 input scenarios for portfolio development, covering alternative (1) Energy Gateway transmission configurations, (2) CO_2 tax levels and regulation types, (3) natural gas prices, (4) regulatory renewable acquisition requirements, (4) load forecasts, (5) renewable generation cost and acquisition incentives, and (6) demand-side management resource availability assumptions. The Company also conducted proof-of-concept modeling of coal unit replacements with combined-cycle combustion turbine (CCCT) alternatives, incorporating incremental costs for existing coal plants.

For portfolio modeling, PacifiCorp used three underlying natural gas price forecasts (low, medium, and high) to develop gas price projections that include the impact of CO_2 costs beginning in 2015: no CO_2 tax; "medium" ($19/ton escalating to $29 by 2030); "high" ($25/ton escalating to $68 by 2030); and "low-to-very-high" ($12/ton escalating to $93 by 2030).

PacifiCorp selected top-performing portfolios on the basis of the combination of lowest average portfolio cost and worst-case portfolio cost resulting from 100 Monte Carlo simulation runs. The Monte Carlo runs capture stochastic behavior of electricity prices, natural gas prices, loads, thermal unit availability, and hydro availability. Final preferred portfolio selection considered additional criteria such as risk-adjusted portfolio cost, the 10-year customer rate impact, CO_2 emissions, supply reliability, resource diversity, and future uncertainty and risk of greenhouse gas and renewable portfolio standard (RPS) policies.

The portfolios serving as preferred portfolio candidates exhibited modest resource mix variability in the first 10 years. Every portfolio included a CCCT resource in 2014, a second CCCT in either 2015 or 2016, and frequently a third CCCT in 2019.

Energy efficiency (Class 2 DSM) represents the largest resource added on an average capacity basis across the portfolios through 2030. Cumulative capacity additions ranged from about 2,520 MW to 2,850 MW. The amounts are significantly higher relative to the 2008 IRP and 2008 IRP Update due to larger forecasted potential amounts, updated costs, and a mandated switch to a "Utility Cost" basis for Utah resources. Portfolios contained an average of 160 MW of load control resources (Class 1 DSM), with the bulk added by 2015.

Geothermal resources are selected in every portfolio. However, the lack of state legislation and regulatory pre-approval mechanisms for recovery of dry-hole drilling costs prompted PacifiCorp to exclude geothermal resources from the preferred portfolio. While geothermal resources to date have not been found to be cost-effective in the Company's competitive all-source requests for proposals (RFPs), they will nevertheless continue to be treated as eligible resources in future RFPs.

Taking into consideration the costs of variable energy resource integration, wind capacity additions exhibited the greatest variability across portfolios, ranging from zero to over 2,700 MW. Selection of wind and other renewable resources is highly sensitive to natural gas prices, CO_2 costs, and availability of the federal production tax credit.

Certain distributed generation resources—biomass combined heat and power (CHP) and solar hot water heating—were found to be cost-effective for all portfolios. Utility-scale and distributed solar photovoltaic resources were not found to be cost-effective.

All the portfolios exhibited the same acquisition pattern for front office transactions[2] through 2014, increasing to a peak of about 1,420 MW in 2013, and then decreasing to a low of approximately 750 MW each year after 2020. Variability between 2015 and 2020 averaged about 330 MW across the portfolios.

The 2011 IRP Preferred Portfolio

PacifiCorp's preferred portfolio consists of a diverse mix of resources. Table ES.3 lists the resource types and annual megawatt capacity additions for 2011 through 2030, while Figure ES.4 shows how the preferred portfolio, along with existing resources, meets capacity requirements through 2020. The portfolio takes advantage of favorable natural gas and electricity prices in the first 10 years of the planning horizon through a combination of CCCT additions and firm market purchases. The cost advantages and risk mitigation benefits of DSM are realized through average annual energy efficiency measure additions equivalent to about 130 MW, along with 250 MW of load control added through 2015. In recognition of long-run public policy goals and regulatory compliance and incentive uncertainty, PacifiCorp also includes 2,100 MW of wind added in increments of 100 to 300 MW beginning in 2018, as well as the Oregon solar initiative requirements. For the first 10 years, these additions are nearly the same as the amount added for the 2008 IRP Update.

As part of the acquisition path analysis documented in Chapter 9, the Company anticipates altering the renewable acquisition timing and strategy to align with legislative, regulatory, technology and market developments.

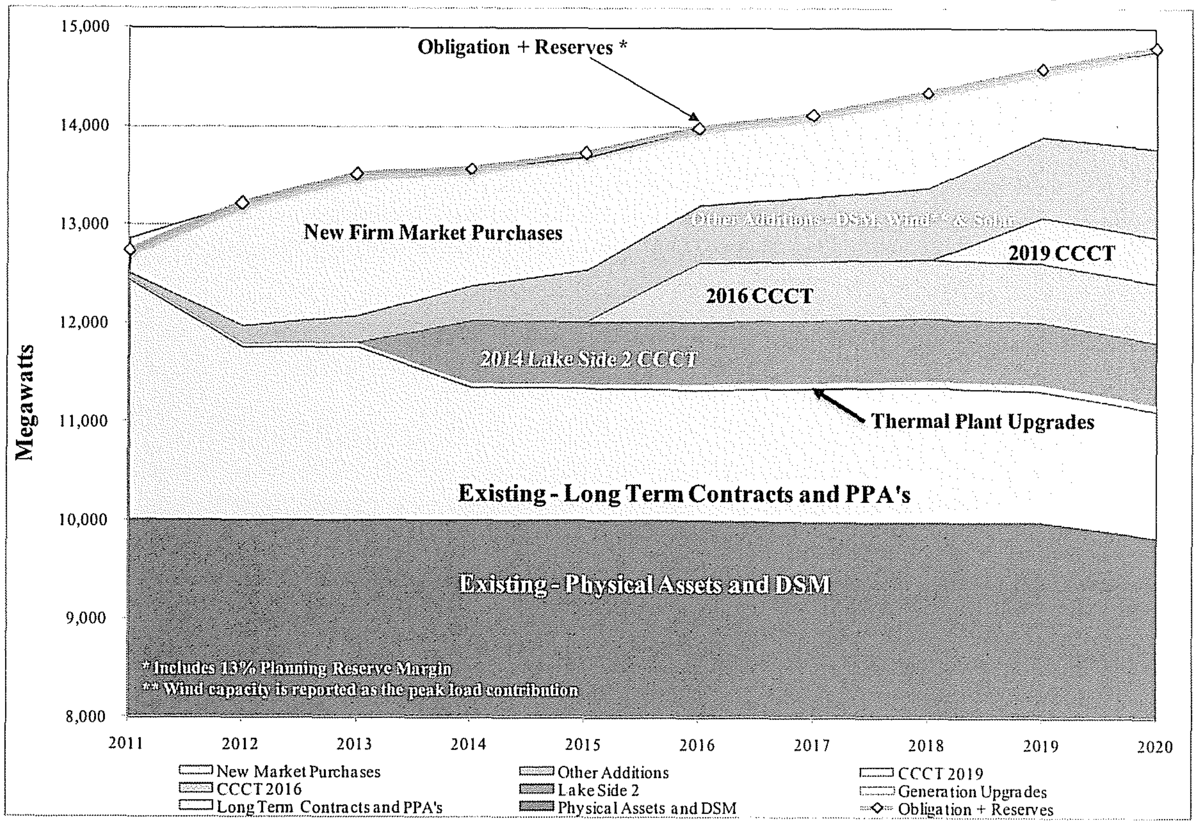
Table ES.3 – 2011 IRP Preferred Portfolio

	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.

[2] Front office transactions (FOT) are proxy market purchases, assumed to be firm, that represent procurement activity made on a forward basis to help the Company cover short positions. PacifiCorp modeled two FOT types for all portfolios: an annual flat product and a third-quarter heavy load hour product.

Figure ES.4 – Addressing PacifiCorp's Peak Capacity Deficit, 2011 through 2020



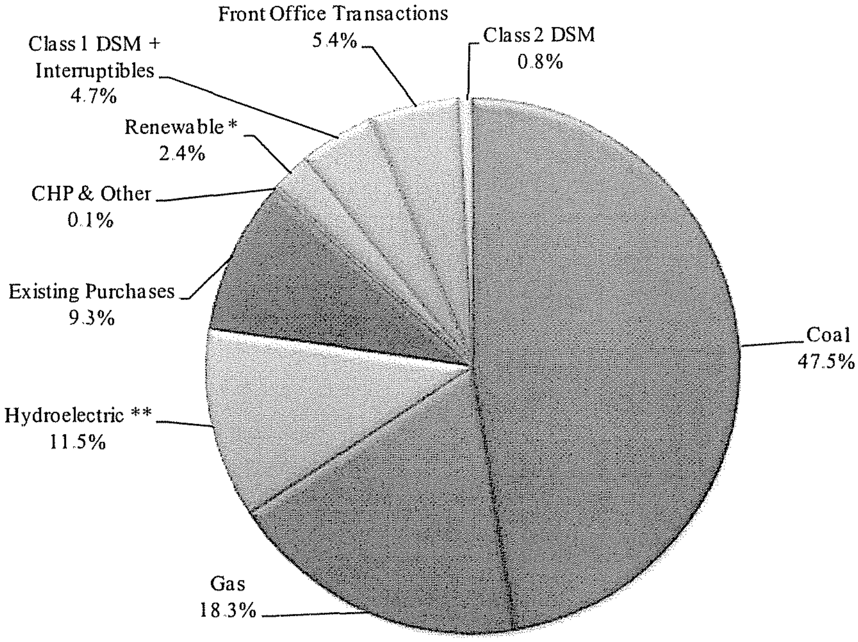
Major resource differences relative to the 10-year portfolio reported in the 2008 IRP Update report include the following:

- Three CCCT resources included in the portfolio by 2019 rather than just two, driven by an increased planning reserve margin (12 to 13 percent), lowered expectations for irrigation load control program capacity, and lower gas prices.
- Significantly more energy efficiency and dispatchable load control—312 MW and 79 MW, respectively.
- 60 MW less wind, which is largely driven by a one-year deferral of the Windstar - Gateway West transmission project from 2017 to 2018.

Figure ES.5 shows the resource capacity mix for representative years 2011 and 2020.

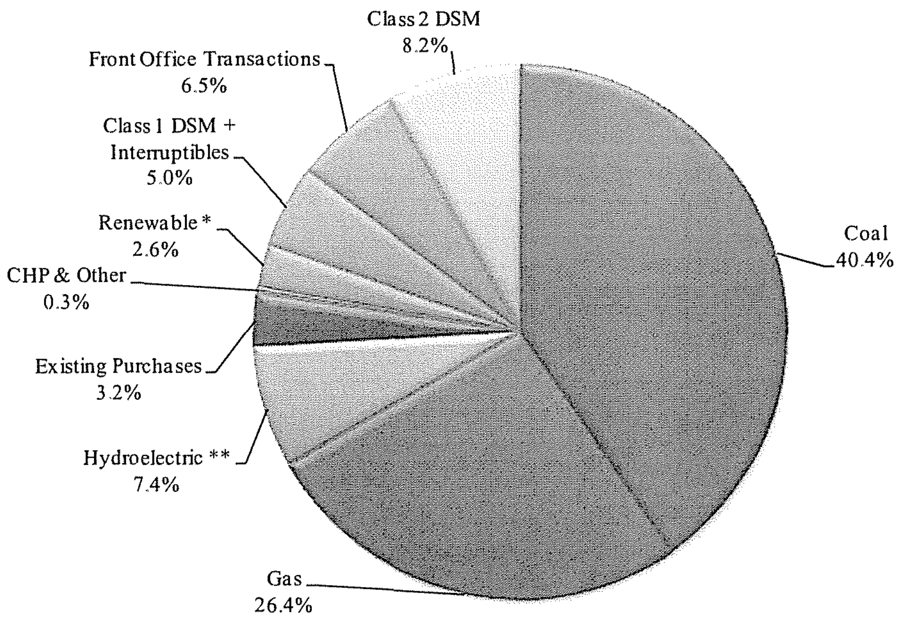
Figure ES.5 – Current and Projected PacifiCorp Resource Capacity Mix

2011 Resource Capacity Mix with Preferred Portfolio Resources



* Renewable resources include wind, solar and geothermal. Wind capacity is reported as the peak load contribution.
Renewable capacity reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases.

2020 Resource Capacity Mix with Preferred Portfolio Resources



* Renewable resources include wind, solar and geothermal. Wind capacity is reported as the peak load contribution.
Renewable capacity reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases.

Figure ES.6 shows PacifiCorp's forecasted RPS compliance position for the California, Oregon, and Washington[3] programs, along with a federal RPS program scenario[4], covering the period 2010 through 2020 based on the preferred portfolio. Utah's RPS goal is tied to a 2025 compliance date, so the 2010-2020 position is not shown below. However, PacifiCorp meets the Utah 2025 state target of 20 percent based on eligible Utah RPS resources, and has significant levels of banked RECs to sustain continued future compliance. As an IRP planning assumption, PacifiCorp anticipates utilizing flexible compliance mechanisms such as banking and/or tradable RECs where allowed, to meet RPS requirements.

Figure ES.6 – Annual State and Federal RPS Position Forecasts

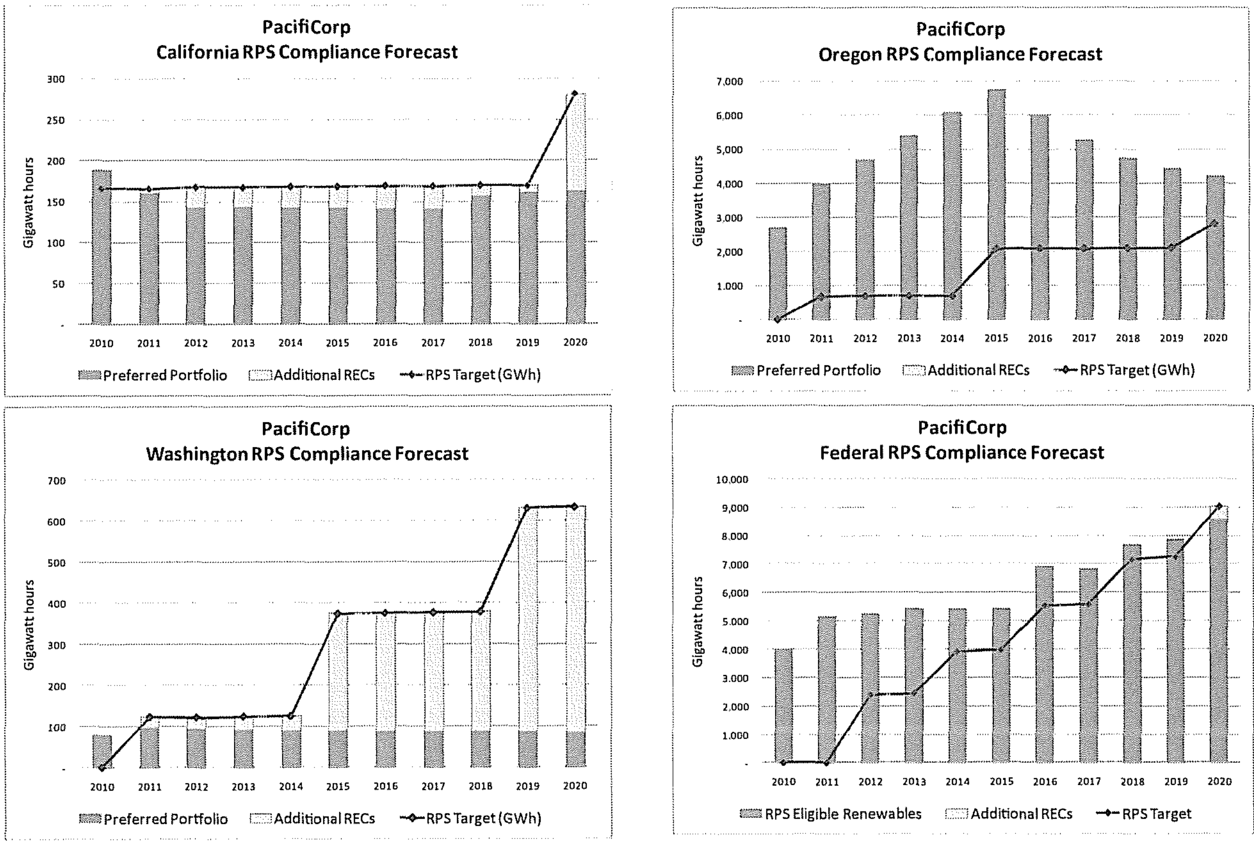
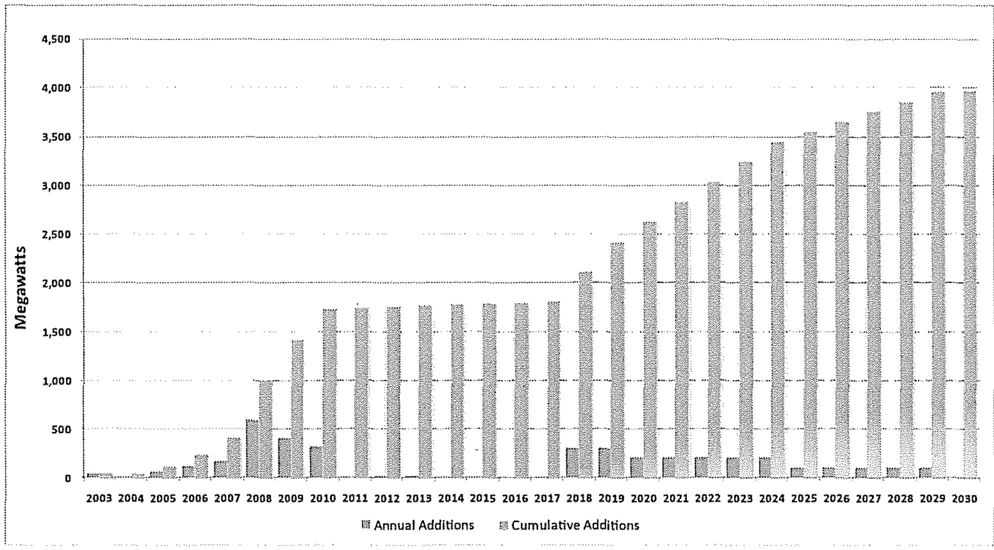


Figure ES.7 shows annual and cumulative additions of renewable resource installed capacity for 2003 through 2030. As indicated, the Company has already exceeded its MidAmerican Energy Holdings Company and PacifiCorp merger commitment to acquire 1,400 MW of cost-effective renewable resources by 2015.

[3] The Washington RPS requirement is tied to January 1st of the compliance year, beginning in 2012.
[4] The forecasted federal RPS position is a scenario based on the Waxman-Markey legislation with targets of 6 percent beginning in 2012, 9.5 percent in 2014, 13 percent in 2016, 16.5 percent in 2018, and 20 percent in 2020.

Figure ES.7 – Annual and Cumulative Renewable Capacity Additions, 2003-2030



Note: the renewable energy capacity reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.

Regarding CO_2 emissions, near-term reductions are driven by plant dispatch changes in response to assumed CO_2 prices. In the longer term, cumulative energy efficiency and wind additions help offset emissions stemming from resource growth needed to meet load obligations. Figure ES.8 illustrates these emission trends for the preferred portfolio under both the medium and low natural gas price scenarios. Figure ES.9 shows the resource generation mix for 2011 and 2020 assuming the medium CO_2 tax and natural gas price trajectories. As indicated, gas resources become more heavily utilized in response to the CO_2 tax, which reaches \$24/ton in 2020.

Figure ES.8 – Carbon Dioxide Generator Emission Trend, \$19/ton CO_2 Tax

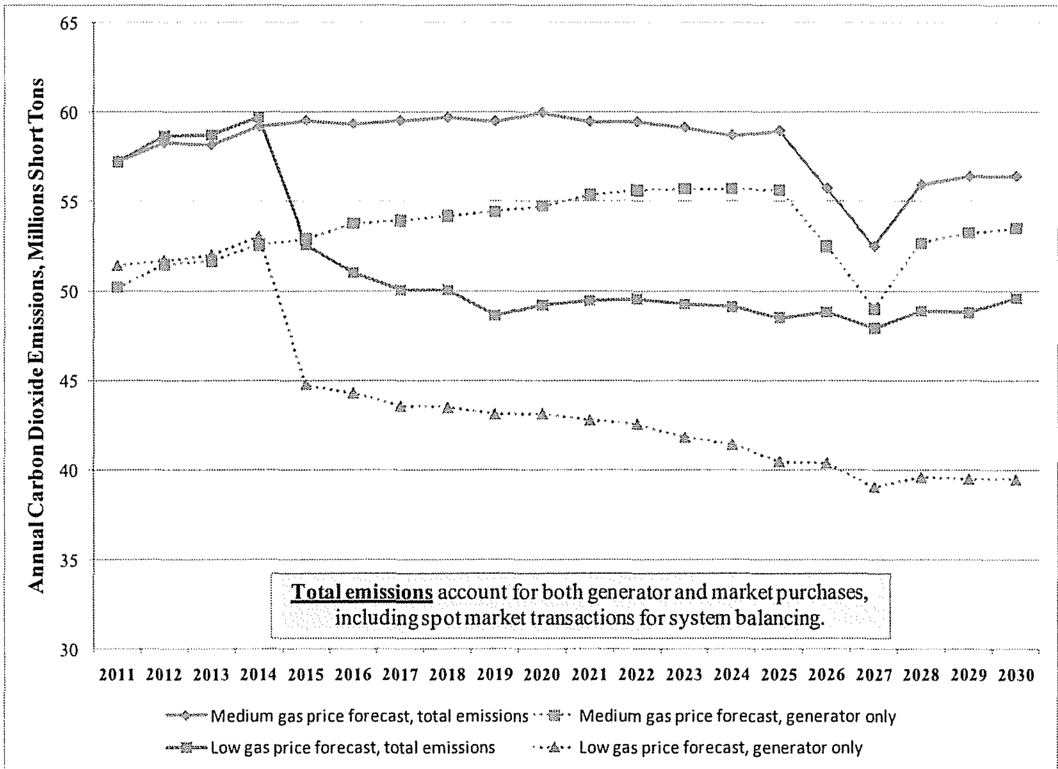
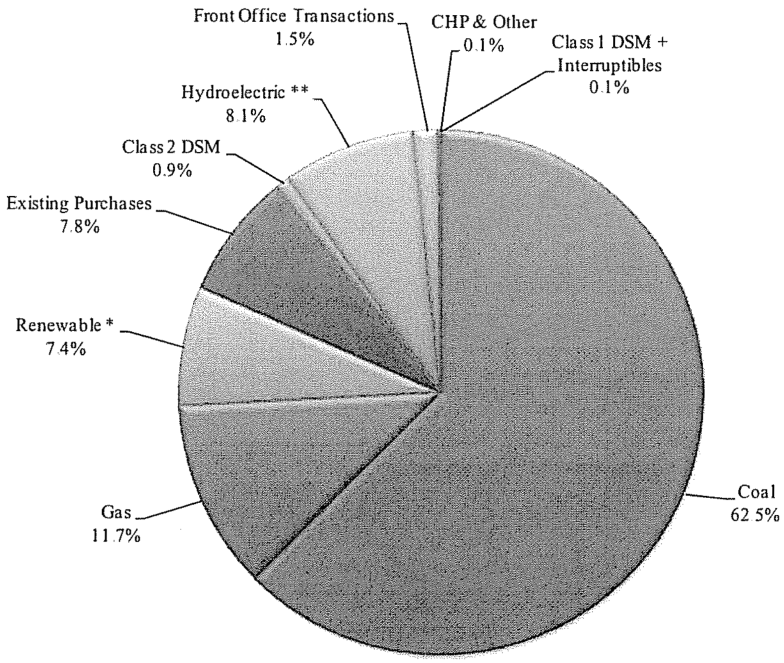


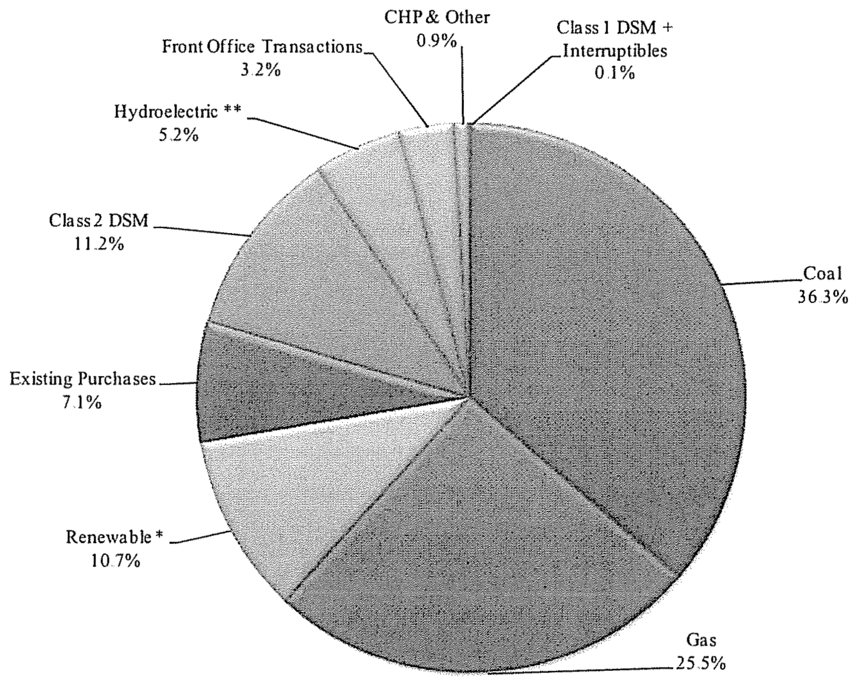
Figure ES.9 – Current and Projected PacifiCorp Resource Energy Mix

2011 Resource Energy Mix with Preferred Portfolio Resources



* Renewable resources include wind, solar and geothermal. Renewable energy generation reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases

2020 Resource Energy Mix with Preferred Portfolio Resources
$24 CO_2 Tax (nominal dollars)



* Renewable resources include wind, solar and geothermal. Renewable energy generation reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases.

The 2011 IRP Action Plan

Table ES.4 – 2011 IRP Action Plan

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**	Wind • *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.* Geothermal • 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. Solar • 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."[5] • *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*

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

Action Item	Category	Timing	Action(s)
			MW in the east side and 12 MW in the west side). Combined Heat & Power (CHP) • *Pursue opportunities for acquiring biomass CHP resources, primarily through 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)* 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.*

Action Item	Category	Timing	Action(s)
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. – ***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.***[6] – ***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.)***

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

Action Item	Category	Timing	Action(s)
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[7], and monitor market changes that may remove the voluntary nature of Class 3 pricing products.
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.

[7] 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.

CHAPTER 2 – INTRODUCTION

PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. This IRP, the 11th plan submitted, fulfills the Company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. It was developed through a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties. As the owner of the IRP and its action plan, all policy judgments and decisions concerning the IRP are ultimately made by PacifiCorp in light of its obligations to its customers, regulators, and shareholders.

This IRP also builds on PacifiCorp's prior resource planning efforts and reflects continued advancements in portfolio modeling and analytical methods. Modeling advancements focused on improvements and expanded use of the Company's capacity expansion optimization model, *System Optimizer*. These advancements include:

- customized enhancements for improved representation of carbon dioxide (CO_2) and renewable portfolio standard (RPS) regulatory futures;
- for the first time, use of System Optimizer for evaluating coal plant utilization and resource replacement scenarios;
- evaluation of multiple Energy Gateway transmission scenarios, along with incorporation of incremental transmission costs for wind resources, and;
- expansion of the west-side model topology to improve representation of transmission constraints and to conduct economic assessment of transmission projects associated with the Energy Gateway strategy.

Significant studies conducted to support the IRP include:

- an update of the 2007 demand-side management (DSM) and dispersed generation potentials study;
- a geothermal resource study;
- a loss of load study for determining an adequate capacity planning reserve margin for load and resource balance development;
- a state-of-the-art wind integration study;
- market reliance scenario analysis, and;
- evaluation of price hedging strategies.

Finally, this IRP reflects continued alignment efforts with the Company's annual ten-year business planning process. The purpose of the alignment, initiated in 2008, is to:

- provide corporate benefits in the form of consistent planning assumptions,
- ensure that business planning is informed by the IRP portfolio analysis, and, likewise, that the IRP accounts for near-term resource affordability concerns that are the province of capital budgeting, and;

- improve the overall transparency of PacifiCorp's resource planning processes to public stakeholders.

The planning alignment strategy also follows the 2008 adoption of the IRP portfolio modeling and analysis approach for requests for proposals (RFP) bid evaluation. This latter initiative was part of PacifiCorp's effort to unify planning and procurement under the same analytical framework. The Company used this analytical framework for bid evaluation in support of the all-source RFP reactivated in December 2009.

This chapter outlines the components of the 2011 IRP, summarizes the role of the IRP, and provides an overview of the public process.

2011 Integrated Resource Plan Components

The basic components of PacifiCorp's 2011 IRP, and where they are addressed in this report, are outlined below.

- the set of IRP principles and objectives that the Company adopted for this IRP effort, as well as a discussion on customer/investor risk allocation (this chapter).

- an assessment of the planning environment, including PacifiCorp's 2011 business plan—approved by the MidAmerican Energy Holdings Company board of directors in December 2010—market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3).

- a description of PacifiCorp's transmission planning efforts and description of IRP modeling studies conducted to support Energy Gateway transmission financial evaluation (Chapter 4).

- a resource needs assessment covering the Company's load forecast, status of existing resources, and determination of the load and energy positions for the 10-year resource acquisition period (Chapter 5).

- a profile of the resource options considered for addressing future capacity and energy deficits (Chapter 6).

- a description of the IRP modeling, risk analysis, and portfolio performance assessment processes (Chapter 7).

- presentation of IRP modeling results, and selection of top-performing resource portfolios and PacifiCorp's preferred portfolio (Chapter 8).

- an IRP action plan linking the Company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource risks (Chapter 9).

- PacifiCorp's transmission expansion action plan, focusing on the Energy Gateway Transmission project (Chapter 10).

The IRP appendices, included as a separate volume, comprised of a detailed load forecast report (Appendix A), fulfillment of IRP regulatory compliance requirements, (Appendix B), detailed modeling results for Energy Gateway transmission scenario analysis (Appendix C), detailed IRP modeling results (Appendices D and E), the public input process (Appendix F), hedging strategy sensitivity analysis (Appendix G), an assessment of resource adequacy for western power markets, including a market reliance "stress" scenario analysis (Appendix H), the Company's 2010 wind integration cost study (Appendix I), the Company's loss of load study (Appendix J), an assessment of the applicability and impact of moving from a one-hour to 18-hour sustained hydro peaking capability standard (Appendix K), and historical plant water consumption data (Appendix L).

2011 IRP Supplement

PacifiCorp intends to file a 2011 IRP supplement report with the state commissions that includes results of additional studies that could not be completed in time to include in this IRP report. These studies consist of the following:

- Stochastic analysis of the Energy Gateway transmission scenarios documented in Chapter 4.
- A cost impact analysis of an "Energy Gateway Central only[8]" scenario that focuses on transmission constraints associated with out-year resources besides wind.
- An energy efficiency avoided cost study (decrement analysis).
- Response to stakeholder (Interwest Energy Alliance) submission of alternate wind capital cost and capacity information on January 10, 2011.

This IRP supplement report will be filed upon completion of these studies, expected in the second quarter of 2011.

The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[9] The main role of the IRP is to serve as a roadmap for determining and implementing the Company's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, risk, and uncertainty. As a business planning tool, it supports informed decision-making

[8] Energy Gateway Central consists of the Populus-Terminal, Mona-Oquirrh, and Sigurd-Red Butte projects.

[9] The Public Utility Commission of Oregon and Public Service Commission of Utah cite "long run public interest" as part of their definition of integrated resource planning. Public interest pertains to adequately quantifying and capturing for resource evaluation any resource costs external to the utility and its ratepayers. For example, the Public Service Commission of Utah cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decision-making process.

on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting RFP bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

While PacifiCorp continues to plan on a system-wide basis, the Company recognizes that new state resource acquisition mandates and policies add complexity to the planning process and present challenges to conducting resource planning on this basis.

Public Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public process allowing stakeholder involvement in all phases of plan development. The Company held 13 public meetings/conference calls during 2010 and early 2011 designed to facilitate information sharing, collaboration, and expectations setting for the IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Table 2.1 lists the public meetings/conferences and major agenda items covered.

Table 2.1 – 2011 IRP Public Meetings

Meeting Type	Date	Main Agenda Items
Workshop	2/16/2010	Wind integration cost study
General Meeting	4/28/2010	2011 IRP kickoff meeting
State Stakeholder Input	6/16/2010	Oregon / California stakeholder comments
State Stakeholder Input	6/29/2010	Utah stakeholder dialogue session
State Stakeholder Input	7/28/2010	Idaho dialogue session
General Meeting	8/4/2010	DSM, supply-side resources, planning reserve margin, proposed portfolio development
State Stakeholder Input	8/11/2010	Wyoming stakeholder dialogue session
General Meeting	10/5/2010	Energy Gateway, load forecast, hedging strategy, market reliance, preliminary load and resource balance, portfolio development case definition
State Stakeholder Input	12/9/2010	Geothermal resource modeling and risk assessment
General Meeting	12/15/2010	Supply-side resource update, final capacity/energy load and resource balances, capacity expansion model set-up, stochastic parameter estimation and research, preferred portfolio selection methodology
General Conference Call	1/27/2011	Solar photovoltaic resource modeling
General Conference Call	1/31/2011	Core case portfolio development results
General Conference Call	2/23/2011	Stochastic production cost modeling results; preferred portfolio selection; coal utilization study results
General Conference Call	3/23/2011	Question & answer session on portfolio modeling results, and discussion on the IRP draft document distributed for public review and comment.

Appendix F provides more details concerning the public meeting process and individual meetings.

In addition to the public meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and consultation throughout the IRP process. The Company maintains a website (http://www.pacificorp.com/es/irp.html), an e-mail "mailbox" (irp@pacificorp.com), and a dedicated IRP phone line (503-813-5245) to support stakeholder communications and address inquiries by public participants.

MidAmerican Energy Holdings Company IRP Commitments

MidAmerican Energy Holdings Company and PacifiCorp committed to continue to produce IRPs according to the schedule and various state commission rules and orders at the time the transaction was in process. Production of the Transaction Commitments Annual Report for 2010 is in progress and due to be filed with each state commission in late May 2011.

CHAPTER 3 – THE PLANNING ENVIRONMENT

Chapter Highlights

Key resource planning considerations shaping the preparation of the 2011 IRP include the following:

- *Decreases in projected natural gas prices relative to the forecasts prepared in 2008 and 2009, caused mainly by the boom in nonconventional domestic gas plays and a favorable long-term supply outlook.*
- *Loss of momentum in federal efforts to develop comprehensive federal energy and climate change compliance requirements, leading to continued uncertainty regarding the long-term investment climate for clean energy technologies. Nevertheless, public and legislative support for clean energy policies at the state level remains robust.*
- *Aggressive efforts by the U.S. Environmental Protection Agency to regulate electric utility plant emissions, including greenhouse gases, criteria pollutants, and other emissions.*
- *Expectations for a more favorable economic environment than assumed in 2009 accompanied by load growth in such areas as data centers and natural resource extraction.*
- *Progress and challenges in planning for, and building, the Energy Gateway transmission project.*
- *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.*

Introduction

This chapter profiles the major external influences that impact PacifiCorp's long-term resource planning as well as recent procurement activities driven by the Company's past IRPs and state resource mandates. External influences are comprised of events and trends affecting the economy and power industry marketplace, along with government policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Specifically addressed in this chapter is PacifiCorp's assessment of the wholesale electricity market, an overview of federal and state environmental and renewable energy policies, hydro relicensing activities, and an update on the Company's resource procurement efforts. Detailed coverage of load growth trends is provided in Appendix A, while transmission expansion planning is addressed in Chapter 4.

Wholesale Electricity Markets

PacifiCorp's system does not operate in an isolated market. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by assuring that resources with the lowest operating costs are serving demand while providing the reliability benefits that arise from a larger portfolio of resources.

PacifiCorp participates in the wholesale market in this fashion, making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on time scales ranging from hourly to years in advance. Without the wholesale market, PacifiCorp or any other load serving entity would need to construct or own an unnecessarily large margin of supplies that would go unutilized in all but the most unusual circumstances and would substantially diminish its capability to efficiently match delivery patterns to the profile of customer demand. The market is not without its risks, as the experience of the 2000-2001 market crisis, followed by the rapid price escalation during the first half of 2008 and subsequent demand destruction and rapid price declines in the second half of 2008, have underscored. Unanticipated paradigm shifts in the market place can also cause significant changes in market prices as evidenced by advancements in the ability of natural gas producers to cost-effectively access abundant shale gas supplies over the past several years.

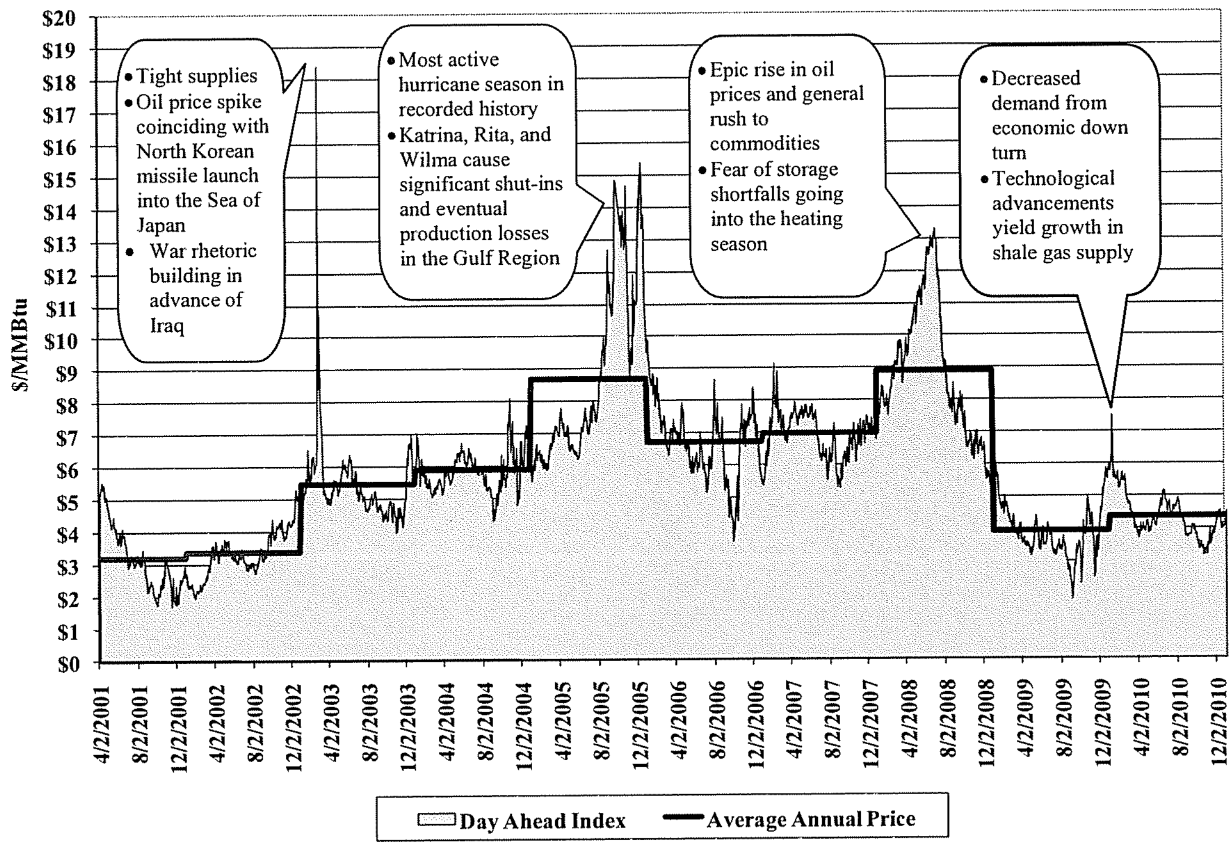
As with all markets, electricity markets are faced with a wide range of uncertainties. However, some uncertainties are easier to evaluate than others. Market participants are routinely studying demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. For example, the Western Electricity Coordinating Council (WECC) publishes an annual assessment of power supply and any number of data services are available that track the status of new resource additions. A review of the WECC power supply assessments is provided in Appendix H. The latest assessment, published in September 2010, indicates that WECC has adequate resources through 2019, while the Basin sub-region, which includes Utah, will have sufficient resources until 2018.

There are other uncertainties that are more difficult to analyze and that possess heavy influence on the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Given the increased role of natural gas-fired generation, gas prices have become a critical determinant in establishing western electricity prices, and this trend is expected to continue over the term of this plan's decision horizon. Another critical uncertainty that weighs heavily on this IRP, as in past IRPs, is the prospect of future greenhouse gas policies. A broad landscape of federal, regional, and state proposals aiming to curb green house gas emissions continues to widen the range of plausible future energy costs, and consequently, future electricity prices. Each of these uncertainties is explored in the cases developed for this IRP and are discussed in more detail below.

Natural Gas Uncertainty

Over the last eight years, North American natural gas markets have demonstrated exceptional price volatility. Figure 3.1 shows historical day-ahead prices at the Henry Hub benchmark from April 2, 2001 through December 2, 2010. Over this period, day-ahead gas prices settled at a low of $1.72 per MMBtu on November 16, 2001 and at a high of $18.41 per MMBtu on February 25, 2003. During the fall and early winter of 2005, prices breached $15 per MMBtu after a wave of hurricanes devastated the Gulf region in what turned out to be the most active hurricane season in recorded history. More recently, prices topped $13 per MMBtu in the summer of 2008 when oil prices began their epic climb above $140 per barrel in the months preceding the global credit crisis. More recently, slow economic growth has reduced demand and abundant shale gas supplies have kept prices below $5 per MMBtu.

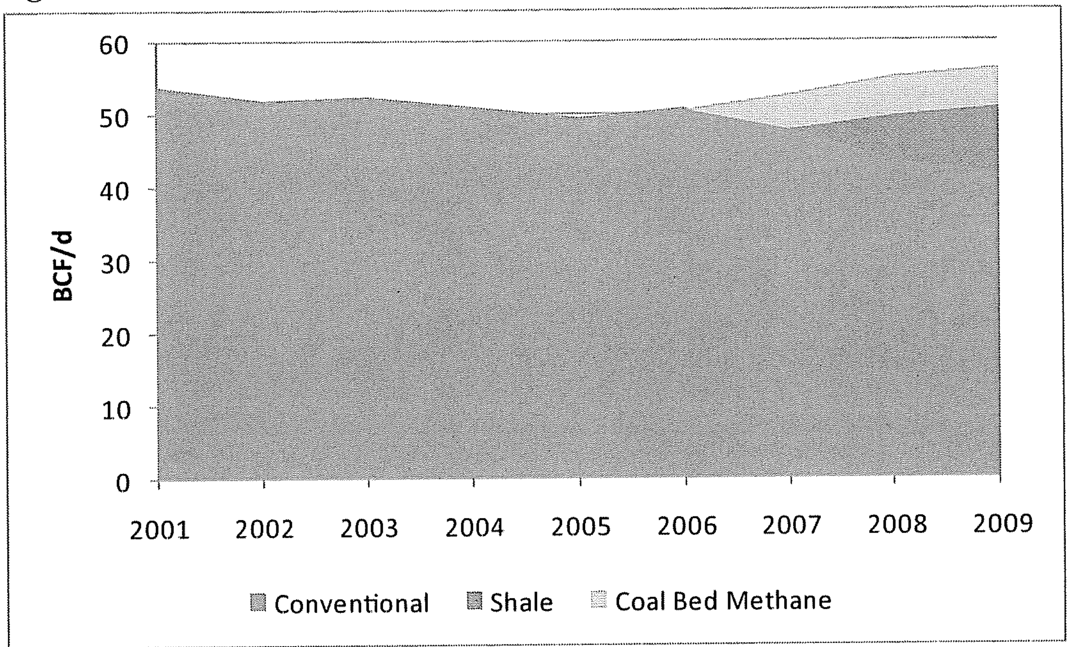
Figure 3.1 – Henry Hub Day-ahead Natural Gas Price History



Source: IntercontinentalExchange (ICE), Over the Counter Day-ahead Index

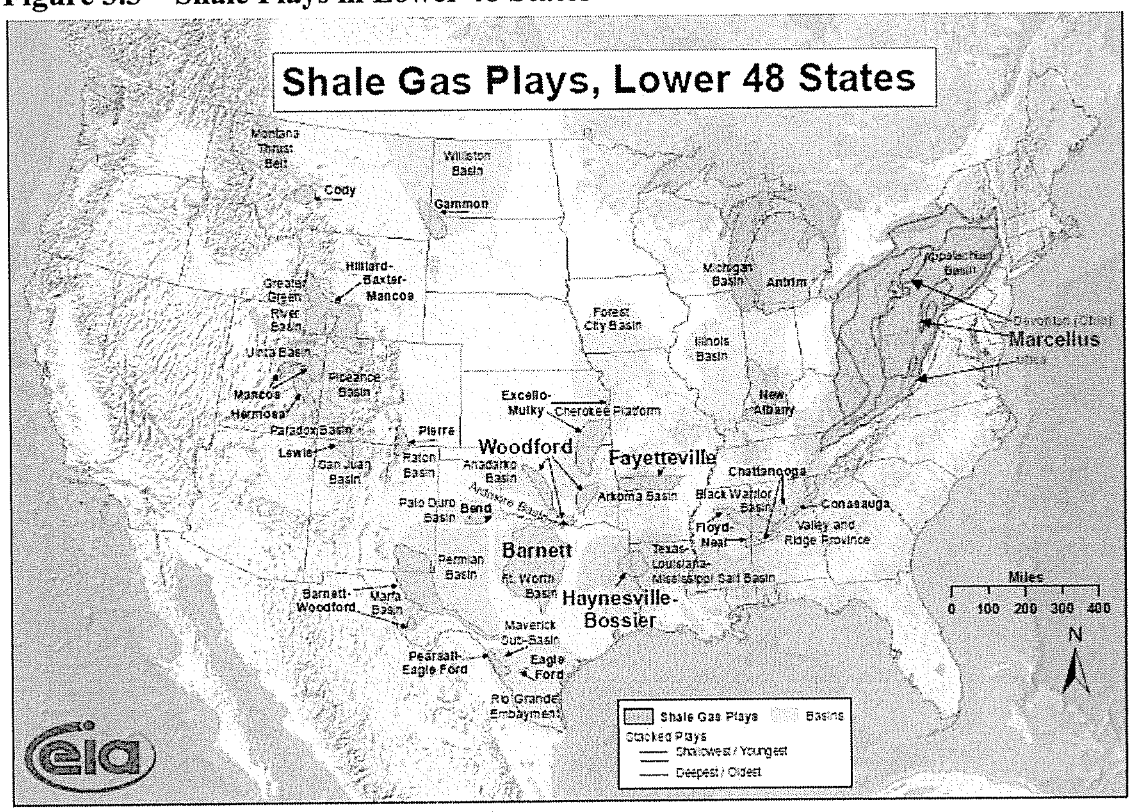
Beyond the geopolitical, extreme weather, and economic events that spawned some rather spectacular highs in the recent past, natural gas prices have exhibited an underlying upward trend from approximately $3 per MMBtu in 2002 to nearly $9 per MMBtu by 2008. Over much of this period, declining volumes from conventional, mature producing regions largely offset growth from unconventional resources. However, prices in 2009 and 2010 buck the trend largely due to reduced demand and significant production gains from unconventional domestic supplies such as coal bed methane and shale. Figure 3.2 shows a breakdown of U.S. supply alongside natural gas demand by end-use sector and Figure 3.3 illustrates the shale gas discoveries ("plays") in the lower 48 states.

Figure 3.2 – Historical Natural Gas Production by Type



Source: U.S. Department of Energy, Energy Information Administration

Figure 3.3 – Shale Plays in Lower 48 States



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

The supply/demand balance began to shift in 2007 and 2008 thanks to an unprecedented and unexpected burst of growth from unconventional domestic supplies across the lower 48 states. With rapid advancements in horizontal drilling and hydraulic fracturing technologies, producers began drilling in geologic formations such as shale. Some of the most prominent contributors to the rapid growth in unconventional natural gas production have been the Barnett Shale located beneath the city of Forth Worth, Texas, the Woodford Shale located in Oklahoma and the Marcellus Shale located in Pennsylvania. Strong growth also continued in the Rocky Mountain region.

Looking forward, many forecasters have historically expected that a gradual restoration of improved supply/demand balance would be achieved largely with growth in liquefied natural gas (LNG) imports. Indeed, there has been tremendous growth in global liquefaction facilities located in major producing regions. This expectation led to significant investments in re-gasification capacity to accommodate the need for future LNG imports. However, the evolution of unconventional supplies and continually growing estimates of shale gas reserves has significantly lowered the outlook for LNG supplies. Currently, U.S. re-gasification capacity is approximately 15.9 BCF/d with 2010 imports at approximately 1.0 BCF/d. The supply outlook as changed dramatically and so quickly that there is now industry chatter suggesting there may be a need to convert some re-gasification facilities to liquefaction facilities as a means to export the newly discovered abundance of domestic natural gas supply.

Several factors contribute to a wide range of price uncertainty in the mid- to long-term. Supporting downside price risk, technological advancements underlying the recent expansion of unconventional supplies opens the door to tremendous growth potential in both production and proven reserves from shale formations across North America. A number of shale formations outside of the Barnett and Woodford have significant upside production potential. Supporting upside price risk, the next generation of unconventional supplies may prove to be more difficult or costly to extract with the possibility of drilling restrictions due to environmental concerns associated with hydraulic fracturing, which would raise marginal costs, and consequently, raise prices. Moreover, a concerted U.S. policy effort to shift the transportation sector away from oil toward natural gas has potential to significantly increase demand, and thus natural gas prices.

Western regional natural gas markets are likely to remain well-connected to overall North American natural gas prices. Rocky Mountain region production has caused prices at the Opal hubs to transact at a discount to the Henry Hub benchmark in recent years. Major pipeline expansions to the mid-west and east coupled with further pipeline expansion plans to the west have provided price support for Opal; however, prices remain discounted to Henry Hub. In the Northwest, where natural gas markets are influenced by production and imports from Canada, prices at Sumas have traded at a premium relative to other hubs in the region. This has been driven in large part by declines in Canadian natural gas production and reduced imports into the U.S. In the near-term, Canadian imports from British Columbia are expected to remain below historical levels lending support for basis differentials in the region; however, in the mid- to long-term, production potential from regional shale formations will have the opportunity to soften the Sumas basis.

The Future of Federal Environmental Regulation and Legislation

PacifiCorp faces a continuously-changing environment with regard to electricity plant emission regulations. Although the exact nature of these changes remains uncertain, they are expected to impact the cost of future resource alternatives and the cost of existing resources in PacifiCorp's generation portfolio.

PacifiCorp's parent company, MidAmerican Electric Holdings Company, has long been an active member of the Edison Electric Institute (EEI) modeling group, particularly with respect to the analysis of potential U.S. Environmental Protection Agency (EPA) regulatory scenarios. Understanding the effect that pending EPA regulations will have on the electric industry remains a critical focus for EEI and its members.

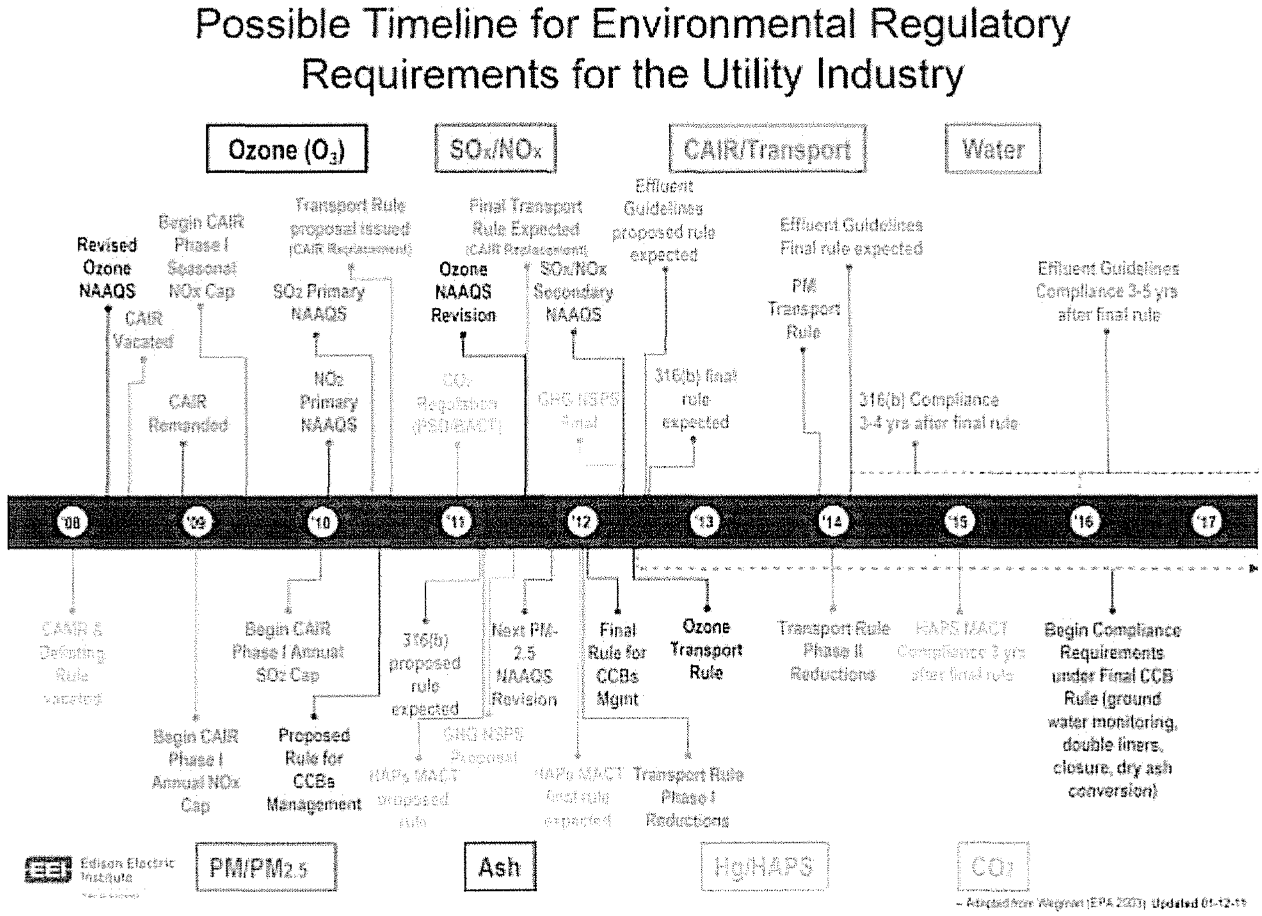
In January 2011, EEI published a report titled "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet", which reflects a collaborative effort by EEI and its members to model a variety of prospective EPA rules for air quality, coal combustion residuals, cooling water intakes, and greenhouse gases. The report summarizes the potential impacts of uncertain regulatory outcomes on unit retirements, capacity additions, pollution control installations, and capital expenditures, based on national-level average input assumptions. As the results contained in the report will help guide PacifiCorp's own prospective modeling efforts, the Company feels it is important to share this report with its IRP stakeholders. This report, and the associated transmittal letter to the EPA, is available on PacifiCorp's IRP Web site.[10]

A Possible Time Horizon for EPA Regulation

The U.S. EPA has undertaken a multi-pronged approach to minimize air, land, and water-based environmental impacts. Many environmental regulations from the EPA are in various parallel stages of development, as outlined on the timeline below (Figure 3.4).

[10]Links to the EPA report transmittal letter and the final report:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/TransmittaltoLisaJacksonFinal28January2011.pdf
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf

Figure 3.4 – EPA Regulatory Timeline for the Utility Industry



Aside from potential greenhouse gas regulations, few of these other regulations are likely to materially impact the industry in isolation; in aggregate, however, they are expected to have a significant impact – especially on the coal-fueled generating units that supply approximately 50 percent of the nation's electricity. As such, each of these regulations will have a significant impact on the utility industry and could affect environmental control requirements, limit operations, change dispatch, and could ultimately determine the economic viability of PacifiCorp's coal-fueled generation assets.

Federal Climate Change Legislation

PacifiCorp continues to evaluate the potential impact of climate change legislation at the federal level. The impact of a given legislative proposal varies significantly depending on its selection of key design criteria (i.e., level of emissions cap, rate of decline of the cap, the use of carbon offsets, allowance allocation methodology, the use of safety valves, and etc.) and macro-economic assumptions (i.e., electricity load growth, fuel prices – especially natural gas, commodity prices, new technologies, etc.).

To date, no federal legislative climate change proposal has successfully been passed by both the U.S. House of Representatives and the U.S. Senate for consideration by the President. The two most prominent legislative proposals introduced for attempted passage through Congress have been the Waxman-Markey bill in 2009 and the Kerry-Lieberman bill in 2010; neither measure was able to accumulate enough support to pass.

In the 112th Congress, several bills have been introduced designed to limit, remove, or suspend EPA's asserted regulatory authority over greenhouse gases. Meanwhile, Congress and the President are likely to look at alternatives to comprehensive climate change legislation, such as a clean energy standard, and deferring the formal proposal of new climate change legislation until a future session of Congress.

EPA Regulatory Update – Greenhouse Gas Emissions

As noted in the regulatory timeline above, the EPA has aggressively pursued the regulation of greenhouse gas (GHG) emissions. Key recent initiatives include the following:

New Source Review / Prevention of Significant Deterioration (NSR / PSD)

On May 13, 2010, the EPA issued a final rule that addresses GHG emissions from stationary sources under the Clean Air Act (CAA) permitting programs, known as the "tailoring" rule. This final rule sets thresholds for GHG emissions that define when permits under the New Source Review (NSR) / Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs are required for new and existing industrial facilities. This final rule "tailors" the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. The rule also establishes a schedule that will initially focus CAA permitting programs on the largest sources with the most CAA permitting experience. Finally, the rule expands to cover the largest sources of GHGs that may not have been previously covered by the CAA for other pollutants.

Guidance for Best Available Control Technology (BACT)

On November 10, 2010, the EPA published a set of guidance documents for the tailoring rule to assist state permitting authorities and industry permitting applicants with the Clean Air Act PSD and Title V permitting for sources of GHGs. Among these publications was a general guidance document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases," which included a set of appendices with illustrative examples of Best Available Control Technology (BACT) determinations for different types of facilities, which are a requirement for PSD permitting. The EPA also provided white papers with technical information concerning available and emerging GHG emission control technologies and practices, without explicitly defining BACT for a particular sector. In addition, the EPA has created a "Greenhouse Gas Emission Strategies Database," which contains information on strategies and control technologies for GHG mitigation for two industrial sectors: electricity generation and cement production.

The guidance does not identify what constitutes BACT for specific types of facilities, and does not establish absolute limits on a permitting authority's discretion when issuing a BACT determination for GHGs. Instead, the guidance emphasizes that the five-step top-down BACT process for criteria pollutants under the Clean Air Act generally remains the same for GHGs. While the guidance does not prescribe BACT in any area, it does state that GHG reduction options that improve energy efficiency will be BACT in many or most instances because they cost less than other environmental controls, may even reduce costs, and other add-on controls for GHGs are limited in number and are at differing stages of development or commercial availability. Utilities have remained very concerned about the NSR implications associated with the tailoring rule (the requirement to conduct BACT analysis for GHG emissions) because of great uncertainty as to what constitutes a triggering event and what constitutes BACT for GHG emissions.

New Source Performance Standards (NSPS)

On December 23, 2010, in a settlement reached with several states and environmental groups in New York v. EPA, the EPA agreed to promulgate emissions standards covering GHGs from both new and existing electric generating units under Section 111 of the Clean Air Act by July 26, 2011 and issue final regulations by May 26, 2012.[11] New source performance standards (NSPS) are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare and must be reviewed every eight years. While NSPS were intended to focus on new and modified sources and effectively establish the floor for determining what constitutes BACT, the emission guidelines will apply to existing sources as well.

The emissions guidelines issued by the EPA will be used by states to develop plans for reducing emissions and include targets based on demonstrated controls, emission reductions, costs and expected timeframes for installation and compliance, and may be less stringent than the requirements imposed on new sources. States must submit their plans to the EPA within nine months after the guidelines' publication unless the EPA establishes a different schedule. States have the ability to apply less stringent standards or longer compliance schedules if they demonstrate that following the federal guidelines is unreasonably cost-prohibitive, physically impossible, or that there are other factors that reasonably preclude meeting the guidelines. States may also impose more stringent standards or shorter compliance schedules. Lastly, under Section 111 of the Clean Air Act, the EPA may establish standards that rely upon market mechanisms rather than technology-specific emissions rates.

EPA Regulatory Update – Non-Greenhouse Gas Emissions

The EPA regulatory timeline above identifies several categories of regulations for non-GHG emissions, some of which are discussed below:

[11] EPA also entered into a similar settlement the same day to address greenhouse gas emissions from refineries with proposed regulations by December 15, 2011 and final regulations by November 15, 2012.

Clean Air Act Criteria Pollutants

Currently, PacifiCorp's generation units must comply with the federal Clean Air Act (CAA), which is implemented by the States subject to EPA approval and oversight. The CAA requires the EPA to set National Ambient Air Quality Standards (NAAQS) for certain pollutants considered harmful to public health and the environment. For a given NAAQS, the EPA and/or a state identifies various control measures that once implemented are meant to achieve a quality standard for a certain pollutant, with each standard rigorously vetted by the scientific community, industry, public interest groups, and the general public.

Particulate matter (PM), sulfur dioxide (SO_2), ozone (O_3), nitrogen dioxide (NO_2), carbon monoxide (CO), and lead are often grouped together because under the Clean Air Act, each of these categories is linked to one or more National Ambient Air Quality Standards (NAAQS). These "criteria pollutants", while undesirable, are not toxic in typical concentrations in the ambient air. Under the Clean Air Act, they are regulated differently from other types of emissions, such as hazardous air pollutants and greenhouse gases.

The EPA has recently established new standards for particulate matter, sulfur dioxide, and nitrogen dioxide. In addition, EPA is expected to finalize new ozone standards in 2011.

Clean Air Transport Rule

In July 2009, EPA proposed its Clean Air Transport Rule (Transport Rule), which would require new reductions in SO_2 and NO_X emissions from large stationary sources, including power plants, located in 31 states and the District of Columbia beginning in 2012. The Transport Rule is intended to help states attain NAAQS set in 1997 for ozone and fine particulate matter emissions. This rule replaces the Bush administration's Clean Air Interstate Rule (CAIR), which was vacated in July 2008 and rescinded by a federal court because it failed to effectively address pollution from upwind states that is hampering efforts by downwind states to comply with ozone and PM NAAQS.

PacifiCorp does not own generating units in states identified by the Transport Rule and thus will not be directly impacted; however, the Company intends to monitor amendments to the Transport Rule closely, particularly since there is some indication that the 2014 revisions to the Transport Rule will extend the geographic scope of impacted states.

Regional Haze

While not depicted within the EPA regulatory timeline, EPA's rule to address Regional Haze visibility concerns will drive additional NO_x reductions particularly from facilities operating in the Western United States, including the states of Utah and Wyoming where PacifiCorp operates generating units. Hence, although the Transport Rule has no direct impact on PacifiCorp's states with generation, the impacts of finalized Regional Haze regulatory activity will.

On June 15, 2005, EPA issued final amendments to its July 1999 Regional Haze rule. These amendments apply to the provisions of the Regional Haze rule that require emission controls known as Best Available Retrofit Technology (BART), for industrial facilities meeting certain regulatory criteria that with emissions that have the potential to impact visibility. These pollutants include $PM_{2.5}$, NO_X, SO_2, certain volatile organic compounds, and ammonia. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART as well as establishing BART emissions limits for those facilities. These facilities are expected to install additional emissions controls usually within five years after the EPA approves a state's Regional Haze plan (2014-2017). In early 2011, both Utah and Wyoming amended their state implementation plans and submitted them to EPA for approval.

Mercury and Hazardous Air Pollutants

In March 2005, the EPA issued the Clean Air Mercury Rule (CAMR) to permanently limit and reduce mercury emissions from coal-fired power plants under a market-based cap-and-trade program. However, the CAMR was vacated in February 2008, with the court finding the mercury rules inconsistent with the stipulations of Section 112 of the Clean Air Act.

A replacement Clean Air Act rule, expected in 2011, is aimed at sharply reducing utility emissions of mercury, acid gases and other hazardous air pollutants by establishing a new maximum achievable control technology (MACT) standard, which would require coal- and oil-fired power plants to meet a specified emissions rate for mercury and other hazardous air pollutants.[12] A court-approved settlement requires the new MACT rule to take effect in 2012. Under the Clean Air Act, affected facilities would have three years to comply (2015), with a possible one-year extension that the EPA can grant on a case-by-case basis.

The EPA's actions on mercury and hazardous air pollutants could potentially require the installation of additional pollution control equipment on a number of U.S. coal plants, including those of PacifiCorp; however, the outcome of this rulemaking remains uncertain.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs), including coal ash, are the byproducts from the combustion of coal in power plants.

CCRs are currently considered exempt wastes under an amendment to the Resource Conservation and Recovery Act (RCRA); however, EPA proposed in 2010 to regulate CCRs for the first time. EPA is considering two possible options for the management of CCRs. Both options fall under the Resource Conservation and Recovery Act (RCRA). Under the first proposal, EPA would list these residual materials as special wastes subject to regulation under Subtitle C of RCRA with requirements from the point of generation to disposition including the closure of disposal units. Under the second proposal, EPA would regulate coal combustion

[12] In addition to mercury, the hazardous air pollutants MACT rule would regulate: 1) acid gases, using hydrogen chloride (HCl) as a surrogate for all the acid gases, 2) non-mercury metals (such as arsenic, lead, and selenium) using particulate matter (PM) as a surrogate; 3) dioxins and furans; and 4) semi and volatile organics.

residuals as nonhazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of coal combustion residuals. A final rule is expected in 2012.

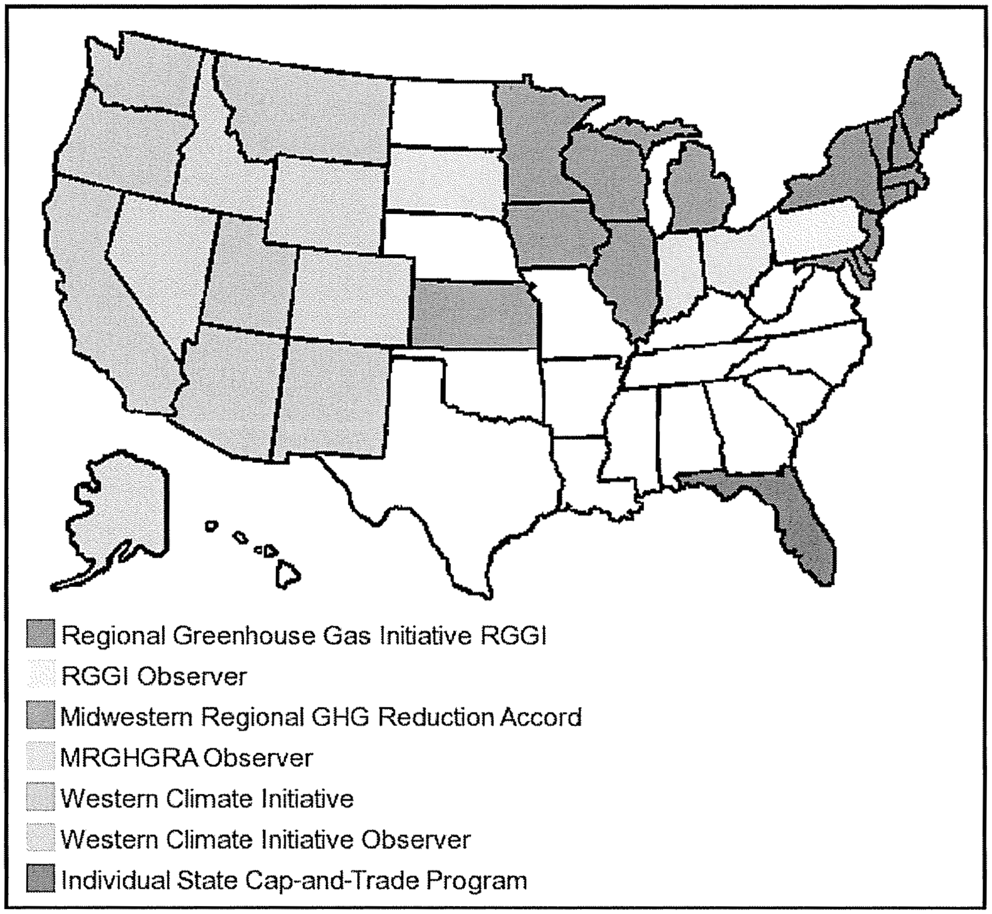
Regional and State Climate Change Regulation

While national greenhouse gas legislation has yet to be successfully adopted, regional and state initiatives continue with the active development of climate change regulations that will impact PacifiCorp.

Regional Climate Change Initiatives

As shown in the map below depicting the various initiatives, the most prominent regional program is the Western Climate Initiative, with the Regional Greenhouse Gas Initiative continuing its development for the Eastern U.S.

Figure 3.5 – Regional Climate Change Initiatives



Western Climate Initiative

Launched in February 2007, the Western Climate Initiative is a collaborative effort comprising seven United States governors and four Canadian Premiers. The Western Climate Initiative was created to identify, evaluate, and implement collective and cooperative ways to reduce greenhouse gases in the region, focusing on a market-based cap-and-trade system.

In September 2008, the Western Climate Initiative Partners released their proposal for a regional cap-and-trade program. The seven states and four provinces would cover 20 percent of the United States and 70 percent of the Canadian economies. Covered emitters include electricity generators and industrial and commercial stationary sources that emit more than 25,000 metric tons of carbon dioxide equivalent per year. The first phase of the cap and trade program is scheduled to begin in 2012. Beginning in 2015, the market would expand to also cover petroleum-based fuel combustion from residential, commercial, and industrial operations, for an overall goal of reducing emissions to 15 percent below 2005 levels by 2020. The proposed market has also been designed with future linkages to other regions, possibly including a federal market and other regional systems.

In July 2010, the Western Climate Initiative's Partners updated its September 2008 recommendations with the release of the Design for the Western Climate Initiative Regional Program, which was a comprehensive strategy to meet the objectives of reducing greenhouse gas emissions, stimulating development of clean-energy technologies, creating green jobs, increasing energy security, and protecting public health. It is a plan to reduce regional GHG emissions to 15 percent below 2005 levels by 2020, and is the culmination of two years of work by seven U.S. states and four Canadian provinces.

By the end of 2010, only California, New Mexico, and several Canadian Provinces were participating in the initial phase of the Western Climate Initiative. California is continuing to finalize its mandatory GHG reporting and cap-and-trade compliance program rules in 2011 in anticipation of a 2012 program start.[13] New Mexico, while adopting cap-and-trade rules in December 2010 that are linked to the progression of the Western Climate Initiative, has a new governor who has expressed concern over implementation of the state rule in 2013.

Washington and Oregon are both Western Climate Initiative Partners and may implement similar programs in a subsequent phase, but no formal plans have been announced in either state.

State-Specific Initiatives

Many states have developed climate action plans and the formation of legislative advisory groups. PacifiCorp continues to actively monitor and participate in state and regional policy discussions relevant to all of its retail jurisdictions.

California

An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80 percent below 1990 levels by 2050. In 2006, the California Legislature passed and Governor Schwarzenegger signed

[13] A tentative ruling by a San Francisco County Superior Court judge in *Association of Irritated Residents, et al. v. California Air Resources Board (CARB)*, issued January 21, 2011, halted implementation of California's greenhouse gas rules because CARB failed to properly consider alternatives to cap-and-trade rule. The final impact of this tentative ruling on California's cap-and-trade program is not yet known.

Assembly Bill 32, the Global Warming Solutions Act of 2006, which set the 2020 greenhouse gas emissions reduction goal into law. It directed the California Air Resources Board to begin developing discrete early actions to reduce greenhouse gases while also preparing a scoping plan to identify how best to reach the 2020 limit. The reduction measures to meet the 2020 target are to become effective by 2012.

On December 12, 2008 the California Air Resources Board approved a scoping plan for Assembly Bill 32. The Assembly Bill 32 scoping plan contains the primary strategies California will use to reduce the greenhouse gases that cause climate change. The scoping plan has a range of greenhouse gases reduction actions which include mandatory reporting requirements, direct regulations, alternative compliance mechanisms, monetary and non-monetary incentives, voluntary actions, market-based mechanisms such as a cap-and-trade system, greenhouse gas emission performance standards, and an implementation fee regulation to fund the program.

On December 16, 2010, the California Air Resources Board approved resolutions to move forward with the finalization of two important rulemaking initiatives pursuant to the goals of Assembly Bill 32: (1) a state-wide cap-and-trade compliance program and (2) significant amendments to the existing mandatory reporting regulation. Under these two programs , utilities that report greenhouse gas emissions related to serving California retail customers are required to meet compliance obligations using cap-and-trade allowances that are either administratively allocated to emitting entities or purchased via auction. Both regulations will be finalized during 2011 and take effect starting in January 2012.

Oregon and Washington

The Washington and Oregon governors signed executive orders in May 2007 and August 2007, respectively, establishing economy-wide goals for the reduction of greenhouse gas emissions in their respective states. Washington's goals seek to (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25 percent below 1990 levels; and (iii) by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below Washington's forecasted emissions in 2050. Oregon's goals seek to (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10 percent below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75 percent below 1990 levels. Each state's legislation also calls for state government developed policy recommendations in the future to assist in the monitoring and achievement of these goals. In addition, Washington adopted legislation that imposes a greenhouse gas emission performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility.

During the 2009 legislative sessions for Washington and Oregon, cap-and-trade legislation was introduced in both states. The legislation would give the states statutory authority to participate in the Western Climate Initiative. However, both legislatures adjourned without reaching consensus on climate change legislation. New proposals for carbon-related legislation is expected for the 2011 legislative sessions in both Washington and Oregon, as is the submission to the Oregon state legislature of the Oregon Global Warming Commission's final report, which will contain a recommended roadmap for Oregon to addressing greenhouse gas emissions.

Renewable Portfolio Standards

A renewable portfolio standard (RPS) is a policy that obligates each retail seller of electricity to include in its resource portfolio (the resources procured by the retail seller to supply its retail customers) a certain amount of electricity from renewable energy resources, such as wind and solar energy. The retailer can satisfy this obligation by either (1) owning a renewable energy facility and producing its own power, or (2) purchasing renewable electricity from someone else's facility.

Some RPS statutes or rules allow retailers to trade their obligation as a way of easing compliance with the RPS. Under this trading approach, the retailer, rather than maintaining renewable energy in its own energy portfolio, instead purchases tradable credits that demonstrate that another electricity provider has generated the required amount of renewable energy.

RPS policies are currently implemented at the state level (although interest in a federal RPS is expanding), and vary considerably in their requirements with respect to timeframe, resource eligibility, treatment of existing plants, arrangements for enforcement and penalties, and whether they allow trading of renewable energy credits. By 2008, twenty-five states had adopted mandatory renewable portfolio standards, five states had adopted voluntary renewable portfolio standard, and fourteen states had adopted no form of renewable portfolio standard.

Within PacifiCorp's service territory, California, Oregon, and Washington have mandatory renewable portfolio standards, with Utah having adopted a voluntary renewable portfolio standard. Each of these states is summarized in Table 3.1, with additional discussion below.

Table 3.1 – Summary of state renewable goals (as applicable to PacifiCorp)

State	Goal
California	Obtain 20 percent of electricity from renewable resources by 2010. Renewable procurement compliance obligation is increased to 33 percent by 2020.
Oregon	Obtain at least 25 percent of electricity sold by the utility to retail electricity consumers from qualifying electricity, as defined, by 2025 in the following increments: • 5 percent: 2011 – 2014 • 15 percent: 2015 – 2019 • 20 percent : 2020 – 2024 • 25 percent: 2025 and beyond
Utah	To the extent it is cost effective, by 2025, obtain 20 percent of annual adjusted retail sales from cost effective renewable resources, as determined by the Public Service Commission or renewable energy certificates.

State	Goal
Washington	Serve at least 15 percent of load from renewable resources and/or renewable energy credits by 2020 in the following increments: • 3 percent by January 1, 2012 through December 31, 2015 • 9 percent by January 1, 2016 through December 31, 2019 • 15 percent by January 1, 2020 and each year thereafter

California

California law requires electric utilities to increase their procurement of renewable resources by at least one percent of their annual retail electricity sales per year so that 20 percent of their annual electricity sales are procured from renewable resources by no later than December 31, 2010. In March 2010, the California Public Utilities Commission issued a decision to allow the use of tradable renewable energy credits (TRECs) with certain limitation to satisfy a retail seller's California RPS obligation. Several petitions to modify the decision were filed. However, in January 2011, the California Public Utilities Commission issued a decision resolving the petitions for modification and authorized the use of TRECs for the California RPS program. At the time of the publication of this IRP, several applications for rehearing and petitions for modification were filed with the California Public Utilities Commission on the TREC decisions. In September 2010, the California Air Resources Board unanimously adopted a "Renewable Electricity Standard" ("RES") pursuant to Executive Order S-21-09 issued in September 2009 under California's Global Warming Solutions Act to expand existing RPS targets to a 33% by 2020 for most retail sellers of electricity in California, including PacifiCorp. Additional changes to the RES are anticipated, in part due to potential impacts of Senate Bill 23 that was introduced in the California Legislature in January 2011. Senate Bill 23 may impose more restrictive compliance obligations than those set forth in the RES. PacifiCorp cannot predict the final outcome of the California legislation or how the RES or Senate Bill 23 may interact with the requirements of the California RPS.

Oregon

In June 2007, the Oregon Renewable Energy Act was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least five percent in 2011 through 2014, 15 percent in 2015 through 2019, 20 percent in 2020 through 2024, and 25 percent in 2025 and subsequent years. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council area, and a limited amount of unbundled renewable energy credits can be used. The Oregon Public Utilities Commission and the Oregon Department of Energy have adopted rules to implement the initiative.

Utah

In March 2008, Utah's governor signed Utah Senate Bill 202, "Energy Resource and Carbon Emission Reduction Initiative;" legislation supported by PacifiCorp. Among other things, this provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand-side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

Washington

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are three percent of retail sales by January 1, 2012 through 2015, nine percent of retail sales by January 1, 2016 through 2019 and 15 percent of retail sales by January 1, 2020. Qualifying renewable energy sources must be located within the Pacific Northwest. The Washington Utilities and Transportation Commission adopted final rules to implement the initiative.

Federal Renewable Portfolio Standard

In his January 25, 2011, State of the Union address, President Obama proposed a national clean energy strategy, with goals of boosting investment in renewable energy technology, having one million pure battery and plug-in hybrid electric vehicles on the road by 2015, and ensuring that 80% of American electricity comes from clean energy sources by 2035. The President has significantly broadened his previous interpretation of "clean energy" to include nuclear, clean coal with carbon capture and sequestration technology, and natural gas in the definition, in addition to more broadly acknowledged energy sources like wind, geothermal, and solar. Currently, the details of an electricity sector national clean energy standard and a corresponding 80% goal by 2035 remain unclear. Critical aspects of such a program would include the economic incentives or research and development funding to expedite the commercial availability of carbon capture and sequestration and small modular (nuclear) reactors, in addition to an extension of federal production tax credits for renewables.

While the Senate is likely to work on legislation calling for a national clean energy standard, prospects in the House of Representatives are less uncertain. Proponents of a national clean energy standard argue that it would ease the move toward a mandatory cap on greenhouse gas emissions by requiring utilities to invest in low-carbon energy sources. Enactment of such a procurement standard would be a significant shift in the way electric utilities are regulated, as it would dramatically increase the authority of the federal government to dictate the makeup of a utility's energy portfolio—a power currently exercised by state governments.

Renewable Energy Certificates and Renewable Generation Reporting

Absent either a RPS compliance obligation or an opportunity to bank unbundled renewable energy certificate (RECs) for future year RPS compliance, PacifiCorp has historically relied on an assumption that a renewable project may generate $5 per megawatt-hour for five years from the sale of unbundled RECs. Unbundled REC sales have helped mitigate the near-term cost differential between new renewable resources and traditional generating resources.

However, once greenhouse gas emissions are regulated, surplus unbundled REC sales would cease. PacifiCorp assumes if an unbundled REC is sold, then the underlying power (aka "null" power) would likely have a carbon emissions rate imputed upon it by regulatory authorities, thus obligating PacifiCorp to purchase either allowances or carbon offsets sufficient to cover the imputed carbon emissions. By selling an unbundled REC, PacifiCorp may generate revenue, but risks incurring a new carbon liability. Once greenhouse gases are regulated—and until the unbundled REC and carbon markets are reconciled—PacifiCorp plans to cease selling unbundled RECs. As an assumption for portfolio modeling, renewable resource costs do not reflect a revenue credit for unbundled REC sales.

Unless otherwise noted, renewable energy generation reported in the IRP reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements. Reported generation reflects facilities for which PacifiCorp may (1) use the renewable energy attributes to comply with state renewable portfolio standards or other regulatory requirements, (2) sell the renewable attributes to third parties in the form of renewable energy credits or other environmental commodities, or (3) not have title to the ownership of the renewable energy attributes.

Hydroelectric Relicensing

The issues involved in relicensing hydroelectric facilities are multifaceted. They involve numerous federal and state environmental laws and regulations, and participation of numerous stakeholders including agencies, Indian tribes, non-governmental organizations, and local communities and governments.

The value to relicensing hydroelectric facilities is continued availability of hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility as they can be called upon to meet peak customer demands almost instantaneously and provide back-up for intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation. With the exception of two hydroelectric projects, all of PacifiCorp's applicable generating facilities now operate under contemporary Orders from the Federal Energy Regulatory Commission (FERC). The Klamath River hydroelectric project continues to work with parties to reach a settlement agreement on future project conditions, and the Condit project is seeking a Surrender Order to decommission the project.

FERC hydroelectric relicensing is administered within a very complex regulatory framework and is an extremely political and often controversial public process. The process itself requires that the project's impacts on the surrounding environment and natural resources, such as fish and wildlife, be scientifically evaluated, followed by development of proposals and alternatives to mitigate for those impacts. Stakeholder consultation is conducted throughout the process. If resolution of issues cannot be reached in this process, litigation often ensues which can be costly and time-consuming. There is only one alternative to relicensing, that being decommissioning. Both choices, however, can involve significant costs.

The FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other certain criteria. The FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural activities, recreation, land-use, and aesthetics against the project's energy production benefits. However, because some of the responsible state and federal agencies have the ability to place mandatory conditions in the license, the FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency and the U.S. Fish and Wildlife Service have the authority within the relicensing to require installation of fish passage facilities (fish ladders and screens) at projects. This is often the largest single capital investment that will be made in a project and can render some projects uneconomic. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other leading to potentially contrary, or additive, licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in settlement negotiations with stakeholders, the results of which are submitted to the FERC for incorporation into a new license. The FERC welcomes settlement agreements into the relicensing process, and with associated recent license orders, has generally accepted agreement terms.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and generally takes nearly ten or more years to complete, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2008, PacifiCorp had incurred $56.6 million in costs for ongoing hydroelectric relicensing, which are included in Construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As relicensing and/or decommissioning efforts continue for the Klamath River and Condit hydroelectric projects, additional process costs are being incurred that will need to be recovered from customers. Also, new requirements contained in FERC licenses or decommissioning Orders could amount to over $1.2 billion over the next 30 to 50 years. Such costs include capital and operations and maintenance investments made in fish passage facilities, recreational facilities, wildlife protection, cultural and flood management measures as well as project operational changes such as increased in-stream flow requirements to protect fish resulting in lost generation. Over 95 percent of these relicensing costs relate to PacifiCorp's three largest hydroelectric projects: Lewis River, Klamath River and North Umpqua.

Treatment in the IRP

The known or expected operational impacts mandated in the new licenses are incorporated in the projection of existing hydroelectric resources discussed in Chapter 5.

PacifiCorp's Approach to Hydroelectric Relicensing

PacifiCorp continues to manage this process by pursuing a negotiated settlement as part of the Klamath River relicensing process. PacifiCorp believes this proactive approach, which involves meeting agency and others' interests through creative solutions is the best way to achieve environmental improvement while managing costs. PacifiCorp also has reached agreements with licensing stakeholders to decommission projects where that has been the most cost-effective outcome for customers.

Recent Resource Procurement Activities

All-Source Request for Proposals

PacifiCorp reactivated its All-Source Request for Proposal on December 2, 2009. This RFP sought 1,500 MW of cost-effective resource consisting of base load, intermediate load and summer peak resources for 2014 to 2016.[14] Bid responses were due March 1, 2010, and throughout the remainder of 2010 the Company conducted its bid and Company benchmark evaluation under the oversight of Independent Evaluators for both the Oregon and Utah commissions. PacifiCorp received acknowledgment of its final short list of bidders on December 27, 2010 from the Public Utility Commission of Oregon. The Company filed an application for "Approval of a significant Energy Resource" with the Public Service Commission of Utah in December 2010, indicating its intent to acquire a 637 MW gas-fired combined-cycle combustion turbine, to be built adjacent to the Lake Side site in Utah by CH2M Hill E&C, Inc. with an on-line date of June 1, 2014.

Demand-side Resources

The comprehensive demand-side management RFP (2008 DSM RFP) released in November 2008 produced several proposals that are being considered. Additional analysis, contracting and regulatory approvals are required before new programs can be introduced. Contracting for new products accepted under the 2008 DSM RFP are forecast to be complete by the end of 2011 with regulatory approvals and implementation commencing after contracting is complete.

Other procurement work anticipated in the 2011 and early 2012 timeframe include finalizing new contracts generated by competitively re-procuring program delivery services for existing programs and delivery channels; issuing RFPs for program evaluations of existing programs for

[14] PacifiCorp's All-Source RFP website: http://www.pacificorp.com/sup/rfps/2009asr.html

the 2009 - 2010 period and the re-procurement of ongoing irrigation load management services in Utah and Idaho as well as the possible extension of these programs into Oregon, Washington and California.

Oregon Solar Request for Proposal

PacifiCorp issued a request for proposals on November 30, 2010 for solar resources serving Oregon retail load.[15] The system sized must be larger than 500 kW (alternating current) and less than 2 MW (alternating current) and be classified as solar photovoltaic energy systems. This request is in response to a recent Oregon Statute ORS 757.370 pertaining to the solar photovoltaic generating capacity standard, which requires Oregon utilities to acquire at least 20 MW (alternating current). PacifiCorp's share of the total is 8.7 MW. The RFP calls for resources to be on line by December 31, 2011. Responses were due January 7, 2011, and bids are currently undergoing evaluation.

[15] PacifiCorp website for the Solar RFP: http://www.pacificorp.com/sup/rfps/rsolar2010.html

CHAPTER 4 – TRANSMISSION PLANNING

Chapter Highlights

- *PacifiCorp is obligated to plan for and meet its customers' future needs, despite uncertainties surrounding regulation of CO_2 emissions and potential new renewables requirements. The Company's planned transmission additions reflect its belief that energy policies will continue to push toward renewable and low-carbon resources. Regardless of future policy direction, these projects are well aligned with rich and diverse resources throughout the Company's service territory, and represent PacifiCorp's best estimation of the resources that will be needed to cost-effectively and reliably meet its customers' future needs.*
- *The cycle time to add significant new transmission is often much longer than adding generation or securing contractual resources. Transmission additions must be integrated into regional plans before permitting and constructing the physical assets. PacifiCorp's transmission expansion plan requires cooperative planning with regional and sub-regional groups across the West.*
- *The regional focus on transmission planning has also led to opportunities for initiatives between the western sub-regions where efficiencies and mutual benefits may be achieved through a broader reach of expertise and geography. PacifiCorp is participating in the development, testing and early stages of implementation of joint initiatives such as dynamic system scheduling and intra-hour scheduling, and is engaged in the preliminary development of a proposed voluntary energy balancing market for the West.*
- *PacifiCorp's transmission network is also increasingly measured against mandatory federal reliability standards, which require infrastructure sufficient to withstand unplanned outage events. The majority of these mandatory standards are the responsibility of the transmission owner.*
- *PacifiCorp's priority in building Energy Gateway is to meet the needs of its customers.*
- *Regulatory support is critically important to these investments materializing.*
- *For this IRP, a number of Energy Gateway configurations, ranging from Gateway Central to the full Gateway expansion scenario, were investigated in the context of alternate CO_2 cost, natural gas price, and government renewable portfolio standards. PacifiCorp believes that proceeding with the full Gateway expansion scenario is the most prudent strategy given regulatory uncertainty, benefits from resource diversity, and the long lead time for adding new transmission facilities.*

Introduction

This chapter describes the transmission planning approach during the development of the 2011 Integrated Resource Plan, which spanned from January 2010 to March 2011.

PacifiCorp owns one of the largest privately held transmission systems in the United States. The Company's transmission system spans over 15,800 miles across 10 states, interconnecting with more than 80 generating plants and 13 adjacent control areas at 152 interconnection points. This infrastructure is critical to the Company's ability to serve its 1.7 million retail electric customers in Utah, Oregon, Wyoming, Washington, Idaho, and northern California.

As is discussed throughout the 2011 Integrated Resource Plan, PacifiCorp plans extensively to ensure that an optimal combination of resources is utilized to cost-effectively meet its customers' growing demand for electricity. The Company considers a multitude of generation, demand-side management and transmission options. These options are weighed against federal regulations as well as policy goals and requirements that vary from state to state. Due to the lengthy planning, permitting and construction processes required for new transmission, the Company must also anticipate potential new federal regulations, particularly those related to greenhouse gas emissions and renewable energy resources.

In identifying its optimal transmission investment plan, and as detailed in the *Transmission Scenario Analysis* section, the Company evaluated multiple transmission scenarios within two different energy futures – one in which federal and state policies continue to support increasing integration of renewable and low-carbon generation options, and one that assumes carbon legislation and federal/state renewable energy requirements will subside, with the majority of new energy being generated by existing fuel resources.

The uncertainties surrounding federal regulation of CO_2 emissions and potential new renewable energy requirements do not defer PacifiCorp's obligation to plan for and meet its customers' future electricity needs. The Company's planned transmission additions reflect its belief that state and federal energy policies will continue to push toward renewable and low-carbon resources. However, regardless of future policy direction, these projects are well aligned with rich and diverse resource areas throughout the Company's service territory, and represent PacifiCorp's best estimation of the resources that will be needed to cost-effectively and reliably meet its customers' needs over the long term.

What is also important to note is that the cost range for the different transmission scenarios considered is relatively close, which suggests economics do not drive a clear selection. The key question is – what is the best investment based on an assumed future state? PacifiCorp looks to its stakeholders to acknowledge and/or comment on the Company's assumption of a renewable and low-carbon future which underlies the transmission footprint assumed in the preferred portfolio.

Purpose of Transmission

PacifiCorp's bulk transmission network is designed to reliably transport electric energy from generation resources (owned generation or market purchases) to various load centers. There are several related benefits associated with a robust transmission network:

1. Reliable delivery of power to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to supply aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably unscheduled outages.
3. Economic exchange of electric power among all systems and industry participants.
4. Development of economically feasible generation resources in areas where it is best suited.
5. Protection against extreme market conditions where limited transmission constrains energy supply.
6. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff.
7. Increased capability and capacity to access Western energy supply markets.

PacifiCorp's transmission network is a critical component of the IRP process and is highly integrated with other transmission providers in the western United States. It has a long history of reliable service in meeting the bulk transmission needs of the region. Its purpose will become more critical in the future as energy resources become more dynamic and customer expectations become more demanding.

Integrated Resource Planning Perspective

Transmission constraints and the ability to address capacity or congestion issues in a timely manner represent important planning considerations for ensuring that peak load and energy obligations are met on a reliable basis. The cycle time to add significant transmission infrastructure is often much longer than adding generation resources or securing contractual resources. Transmission additions must be integrated into regional plans and then permits must be obtained to site and construct the physical assets. Inadequate transmission capacity limits the utility's ability to access what would otherwise be cost effective generating resources.

Consistent with the requirements of its Open Access Transmission Tariff ("OATT"), approved by the Federal Energy Regulatory Commission ("FERC"), PacifiCorp plans and builds its transmission system based on its network customers' 10-year load and resource forecasts. Per FERC guidelines, the Company is able to reserve transmission network capacity based on this 10-year forecast data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required for significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of load and resource forecasts.[16] A 20-year planning horizon and ability to reserve transmission capacity to meet forecasted need over that timeframe is more consistent with the time required to plan for and build large scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

As discussed in the following sections, PacifiCorp is engaged in a significant transmission expansion effort called Energy Gateway that requires cooperative transmission planning with regional and sub-regional planning groups across the Western Interconnection. Transmission infrastructure will continue to play an important role in future resource plans as segments of Energy Gateway are added over time along with other system reinforcement projects.

Interconnection-wide Regional Planning

Various regional planning processes have developed over the last several years in the Western Interconnection.[17] It is expected that, in the future, these processes will be the primary forums where major transmission projects are identified, evaluated, developed and coordinated. In the Western Interconnection, regional planning has evolved into a three-tiered approach where an interconnection-wide entity, the Western Electricity Coordinating Council (WECC) conducts regional planning at a very high level; several sub-regional planning groups focus with greater depth on their specific jurisdictions; and transmission providers perform local planning studies within their sub-regions. This coordinated planning helps to ensure that customers in the region are served reliably and at the least cost.

Regional Planning

WECC is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection, assuring open and non-discriminatory transmission access and providing a forum for coordinating the operating and planning activities of its members. In 2006, in accordance with the transmission planning principles outlined in the Federal Energy Regulatory Commission's Order 890, WECC took on a larger planning role through the establishment of the Transmission Expansion Planning Policy Committee (TEPPC). In 2009, WECC was awarded nearly $15 million in American Recovery and Reinvestment Act (ARRA) funds to conduct interconnection-wide transmission planning studies. This funding provided for a significant expansion of WECC's transmission planning and stakeholder involvement activities, which are managed by TEPPC.

TEPPC is tasked with engaging stakeholders to evaluate long-term regional transmission needs based on current and projected electric demand, generation resources, energy policies, technology costs, impacts on transmission reliability, and emissions considerations. TEPPC's efforts complement those of WECC members and stakeholders, and the resulting plans will

[16] The application to begin the Environmental Impact Statement process was filed with the Bureau of Land Management in late 2007 for Energy Gateway West. For this particular project, permitting will require five years or more before construction can begin.

[17] The Western Interconnection stretches from Western Canada south to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains.

provide transmission providers and decision makers with thorough, credible information to help guide infrastructure investment decisions throughout the West.

TEPPC organizes and steers WECC's regional economic transmission planning activities, including:

- Steering decisions on key assumptions and the process by which economic transmission expansion planning data are collected, coordinated and validated;
- Approving transmission study plans, including study scope, objectives, priorities, overall approach, deliverables, and schedules;
- Steering decisions on analytical methods and on selecting and implementing production cost and other models found necessary;
- Ensuring the economic transmission expansion planning process is impartial, transparent, properly executed and well communicated;
- Ensuring that regional experts and stakeholders participate, including state and provincial energy offices, regulators, resource and transmission developers, load serving entities, and environmental and consumer advocate stakeholders through a stakeholder advisory group;
- Advising the WECC Board on policy issues affecting economic transmission expansion planning; and
- Approving recommendations to improve the economic transmission expansion planning process.

TEPPC's analyses and studies focus on plans with west-wide implications and include high-level assessments of congestion and congestion costs. The analyses and studies also evaluate the economics of resource and transmission expansion alternatives on a regional, screening study basis. Resource and transmission alternatives may be targeted at relieving congestion, minimizing and stabilizing regional production costs, diversifying fuels, achieving renewable resource and clean energy goals, or other purposes. Alternatives often draw from state energy plans, integrated resource plans, large regional expansion proposals, sub-regional plans and studies, and other sources if relevant in a regional context.

Members and stakeholders of TEPPC include transmission providers, policy makers, governmental representatives, and others with expertise in planning, building new economic transmission, evaluating the economics of transmission or resource plans, or managing public planning processes.

Similar to the TEPPC activities and process at WECC, a similar process exists under the oversight of WECC's Planning Coordination Committee, which provides for the reliability aspects of transmission system planning.

Sub-Regional Planning Groups

Recognizing that planning the entire Western Interconnection in one forum is impractical due to the overwhelming scope of work, a number of smaller sub-regional groups have been formed to address specific challenges in various areas of the Western Interconnection. Generally, all of these forums provide similar regional planning functions, including the development and coordination of major transmission plans within their respective areas. It is these sub-regional forums where the majority of transmission projects are expected to be developed. These forums coordinate with each other directly through liaisons and through TEPPC. A list of sub-regional groups is provided below:

- **NTTG** – Northern Tier Transmission Group
- **CCPG** – Colorado Coordinated Planning Group
- **CG** – Columbia Grid
- **SIERRA** – Sierra Subregional Planning Group
- **SWAT** – Southwest Area Transmission
- **CAISO** – California Independent System Operator
- **CTPG** – California Transmission Planning Group
- **WestConnect** – A southwest sub-regional planning group that includes participants from CCPG, SWAT and other utilities
- **AESO** – Alberta Electric System Operator
- **BC** – BC Hydro

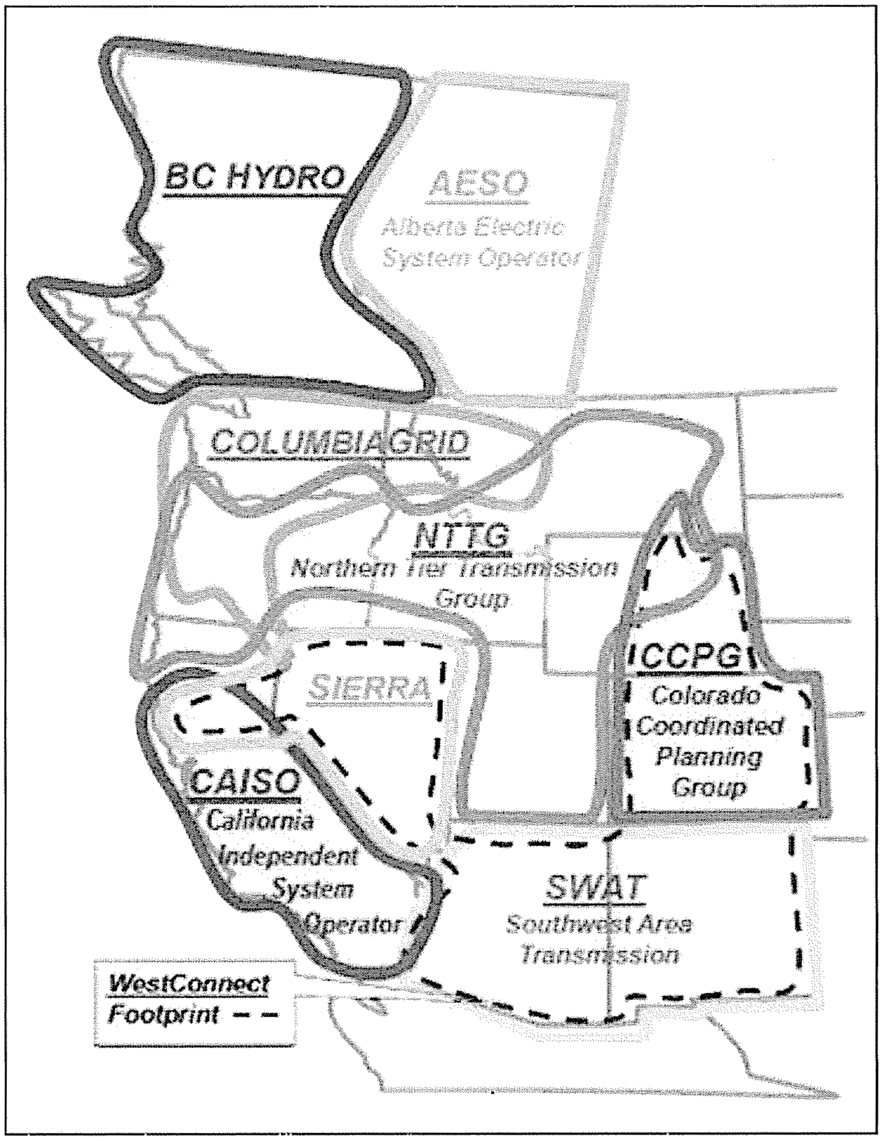
PacifiCorp is one of the founding members of Northern Tier Transmission Group (NTTG). Originally formed in early 2007, NTTG has an overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. NTTG members serve more than four million customers with nearly 30,000 miles of transmission lines within Oregon, Washington, California, Idaho, Montana, Wyoming, and Utah. In addition to PacifiCorp, other members include Deseret Power Electric Cooperative, NorthWestern Energy, Idaho Power, Portland General Electric, and the Utah Associated Municipal Power Systems.

Per the NTTG Steering Committee Charter,[18] PacifiCorp and other members are committed to *"[the] furtherance of ancillary services markets, regional transmission tariffs, common and/or joint Open Access Transmission Tariffs, energy and/or regulation markets, and other transmission products or tariff structures if both economically justified and initiated by unanimity of the Steering Committee."* See the Regional Initiatives section below for examples of programs PacifiCorp and NTTG are engaged in developing.

The geographical areas covered by these sub-regional planning groups are approximately shown in Figure 4.1 below:

[18] NTTG Steering Committee Charter:
http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=1085&Itemid=31

Figure 4.1 – Sub-regional Transmission Planning Groups in the WECC

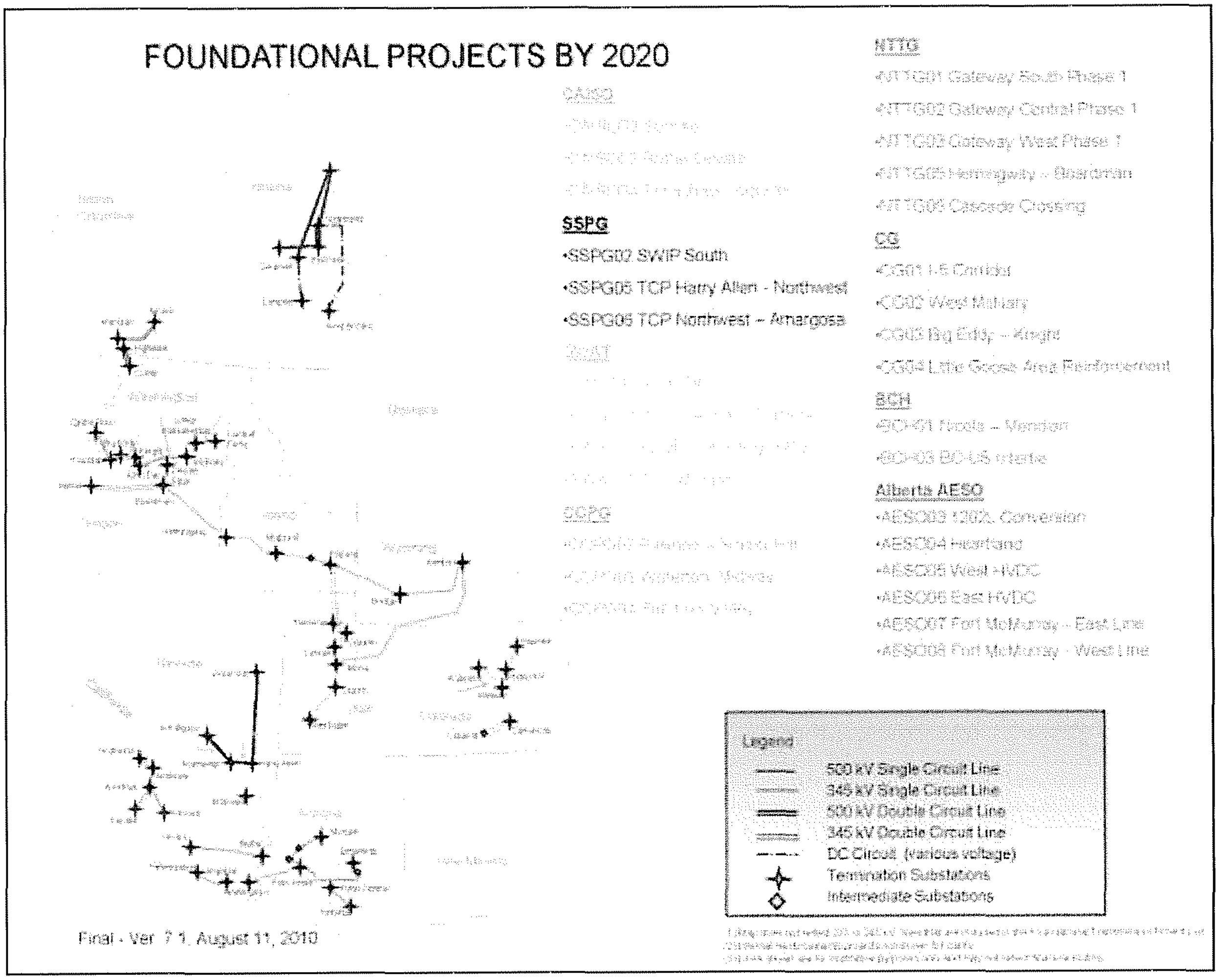


Sub-regional Coordination Group (SCG)

The SCG is a sub group of TEPPC, and is comprised of a member from each of the TEPPC-recognized sub-regional planning groups (including NTTG). The SCG was formed to facilitate WECC's efforts, through TEPPC, to create interconnection-wide transmission plans for the West. Its primary task is the creation of a list of "foundational transmission projects," which represents projects that have a very high probability of being in service in the 2010-2020 timeframe. This list will be used by TEPPC for studies used to develop its 10-year Regional Transmission Plan.

In August 2010, the SCG issued its report to TEPPC; the *Foundational Transmission Project List* "reflects the minimum transmission system additions that have a sufficient level of commitment or defined need to provide WECC with a starting point for the development of their interconnection-wide transmission plans."[19] A map representing all projects on the foundational projects list, including PacifiCorp's Energy Gateway Transmission Expansion projects, is provided below as Figure 4.2.

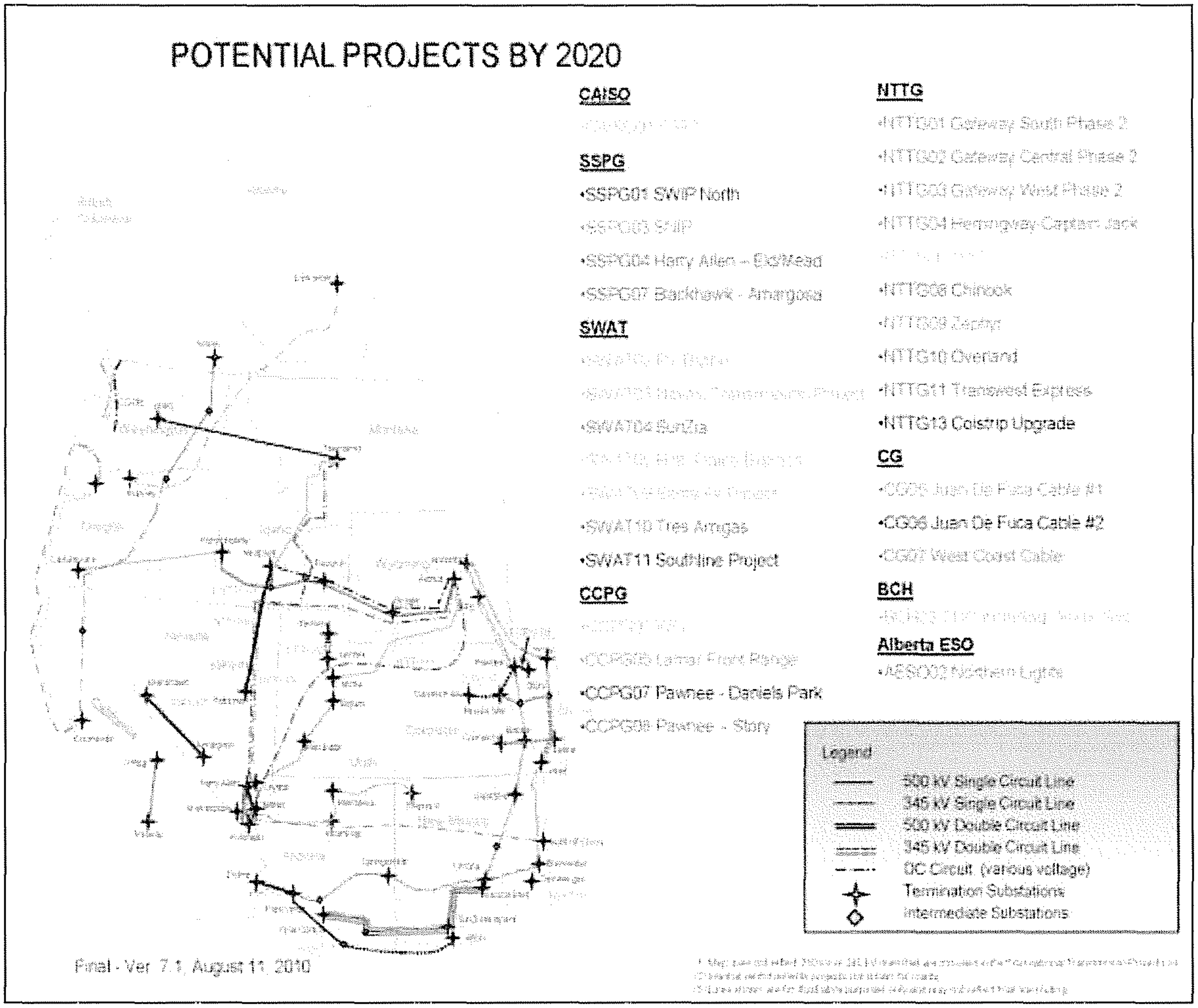
Figure 4.2 – Sub-regional Coordination Group (SCG) Foundational Projects by 2020



The SCG report also includes a list of "potential transmission projects," which represents projects that have been identified in the sub-regional planning groups' 10-year plans but do not meet the criteria (including permitting status, financial commitment, reliability impacts and interconnection-wide significance) to be included on the foundational transmission projects list. These projects were provided for TEPPC to use when selecting additional transmission facilities needed to develop the WECC interconnection-wide transmission plan. A map representing all projects on the potential projects list is provided below as Figure 4.3.

[19] August 2010 SCG Foundational Transmission Projects List: http://www.wecc.biz/committees/BOD/TEPPC/SCG/Shared%20Documents/SCG%20Foundational%20Transmission%20Project%20List%20Report.pdf

Figure 4.3 – Sub-regional Coordination Group (SCG) Potential Projects by 2020



Regional Initiatives

Joint Initiative (JI)

Since 2008, representatives from Northern Tier Transmission Group, ColumbiaGrid and WestConnect have worked together to develop concepts that would achieve mutual benefits through a broader reach of expertise and geography. Through "strike teams" established by the JI, PacifiCorp and other interested parties have supported technical exploration and helped develop programs aimed at achieving transmission system efficiencies and accommodating increasing levels of variable energy resources. Three key tools developed through the JI are:

- *Dynamic System Scheduling* – Developed in order to simplify, enhance and reduce the cost of dynamically scheduling resources between balancing authority areas across the Western Interconnection, providing for the setup and exchange of dynamic schedules on a much more frequent and efficient basis than dynamic schedules currently in place.

- *Intra-hour Transmission Scheduling Business Practices* – Developed to standardize transmission scheduling business practices across multiple transmission service providers to allow for intra-hour changes within a given operating hour; giving transmission customers options for expanding opportunities across participating transmission providers and balancing authorities more frequently than once an hour.

- *Intra-hour Transaction Accelerator Platform* – The I-TAP concept was developed to enable intra-hour bilateral energy and capacity transactions via an internet-accessible "hub" that links the various existing processes used to complete a transaction (such as OASIS, e-Tag author and submission, deal-capture, trading platforms, etc.) to enable high-speed, real-time transactions through a single port of entry.

PacifiCorp is participating in the development, testing and early stages of implementation of each of these programs. For more information on these concepts, please visit the Joint Initiative's website at www.columbiagrid.org/ji-nttg-wc-overview.cfm.

Efficient Dispatch Toolkit (EDT)
WECC and its member organizations and stakeholders are working cooperatively to develop a comprehensive cost benefit study to validate the EDT concept with the goal of optimizing generation and transmission efficiency and maintaining a reliable bulk electric system in the Western Interconnection. The EDT is composed of two separate but related tools—the Energy Imbalance Market and the Enhanced Curtailment Calculator.

- Energy Imbalance Market (EIM) – The proposed EIM would supplement the current bilateral market with real-time balancing via a sub-hourly, real-time energy market that provides centralized, automated, interconnection-wide generation dispatch. This automation is expected to increase system efficiency by providing access to balancing resources located throughout the region and optimizing the overall dispatch through incorporating real-time generation capabilities, transmission availability and constraints, and pricing. While this concept proposes an independent market operator, it does not propose a single consolidated regional tariff or to implement an Independent System Operator (ISO) or Regional Transmission Organization (RTO) in the Western Interconnection. As proposed, participation in the EIM would be voluntary.

- Enhanced Curtailment Calculator (ECC) – The ECC is a proposed tool for calculating curtailment responsibilities, and would calculate curtailments on many more paths—rated and unrated—than the current tool, webSAS, is capable of capturing. The proposed ECC would allow real-time updates of transmission system data to include actual outages, which are currently updated only twice annually, and a more detailed model of the physical system. While the ECC could be developed and implemented independently of the EIM, the ECC plays an integral role in the effectiveness of the proposed EIM.

In 2010, the WECC Board of Directors approved a proposal for detailed analyses of the potential costs and benefits of the EDT. These analyses, which are currently underway, will provide important data to inform the Board and WECC members and help determine next steps of EDT development. PacifiCorp will continue to participate directly in the development of the EDT and, should the concept come to fruition, will base its ultimate decision on whether to participate on the costs and benefits to customers and the impact on transmission system reliability. For more information on the Efficient Dispatch Toolkit, please visit WECC's website at www.wecc.biz/committees/edt/Pages/default.aspx.

Energy Gateway Origins

Since the last major transmission infrastructure construction in the 1970s and early 1980s, load growth and increased use of the western transmission system has steadily eroded any surplus capacity of the network. In the early 1990s, when limited transmission capacity in high growth regions became more severe, low natural gas prices generally made adding gas fired generation close to load centers less expensive than remote generation coupled with transmission infrastructure additions. As natural gas prices started moving up in the year 2000, transmission construction became more attractive, but long transmission lead times and rate recovery uncertainty suppressed new transmission investment.

Numerous regional and sub-regional studies have shown critical need to alleviate transmission congestion and move transmission constrained energy resources to regional load centers. These studies include the September 2004 Rocky Mountain Area Transmission Study[20], the May 2006 Western Governors' Association Transmission Task Force Report[21], the Northern Tier Transmission Group Fast Track Project Process in 2007[22], the TEPPC 2008 Annual Report[23], the 2009 TEPPC Western Interconnection Transmission Path Utilization Study[24], and subsequent PacifiCorp planning studies.

The recommended bulk electric transmission additions for PacifiCorp took on a consistent footprint, which is now known as Energy Gateway, establishing a triangle over Idaho, Utah and Wyoming with paths extending into Oregon and Washington.

Prior to 2007, PacifiCorp transmission activity was primarily focused on maintaining existing transmission reliability, executing queue studies, addressing compliance issues, and participating in shaping regional policy issues. Investments in main grid assets for load service, regional expansion or economic expansion to meet specific customer requests for service were addressed as transmission customers requested service.

New Transmission Requirements

Historically, transmission planning took place at the utility level and was focused on connecting specific utility generation resources to designated load centers. Under Order 888/889 Federal

[20] http://psc.state.wy.us/htdocs/subregional/Reports.htm
[21] http://www.westgov.org/index.php?option=com_joomdoc&task=doc_download&gid=97&Itemid
[22] http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=121&Itemid=31
[23]http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/TEPPC%20Annual%20Reports/2008/CoverLetter_Exec_Summary_Final_.pdf
[24]http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/TEPPC%20Annual%20Reports/2009/2009%20Western%20Interconnection%20Trasnsmission%20Path%20Utilization%20Study.pdf

Energy Regulatory Commission rules, customer requests for transmission service were sporadic and uncoordinated with high levels of uncertainty in many markets which inhibited transmission investments.

Due to PacifiCorp's transmission system being a major component of the Western Interconnection, the Company has the responsibility to provide network customers adequate transmission capability that optimizes generation resources and provides reliable service both today and into the future. Based on current projections, loads and the dynamic blend of energy resources are expected to become more complex over the next twenty years, which will challenge the existing capabilities of the transmission network.

In addition to ensuring sufficient capacity is available to meet the needs of its network customers, the Federal Energy Regulatory Commission in Order 890 encourages transmission providers such as PacifiCorp to plan and implement regional solutions for transmission reliability and expansion.

Based on PacifiCorp customers' aggregate needs, a blueprint for transmission expansion was developed. The expansion plan is a culmination of prior studies and PacifiCorp customers' needs over a long term horizon for new resource development. The expansion plan, now referred to as Energy Gateway, will support multiple load centers, resource locations and resource types, and calls for the construction of numerous transmission segments – totaling approximately 2,000 miles.

The Energy Gateway blueprint uses a "hub and spoke" concept to most efficiently integrate transmission lines and collection points with resources and load centers aimed at serving PacifiCorp customers while keeping in sight regional and sub-regional needs.

In addition to regulatory requirements for regional planning, future siting and permitting of new transmission lines will require significant participation and input from many stakeholders in the west. As part of new transmission line permitting, PacifiCorp will have to demonstrate that several key requirements have been met, including 1) the Company has satisfied an ongoing requirement for transmission to serve customers, 2) the Company is planning and building for the future and is obtaining corridors and mitigating environmental impacts prudently, and 3) that any projects being proposed economically meet the reliability and infrastructure needs of the region overall. This regional process and the Western Electricity Coordinating Council's planning process are considered critical to gaining wide support and acceptance for PacifiCorp's transmission expansion plan.

Customer Loads and Resources

PacifiCorp's Open Access Transmission Tariff ("OATT"), approved by the Federal Energy Regulatory Commission ("FERC"), details the Company's requirements and obligations to provide transmission service. Section 28.2 defines PacifiCorp's responsibilities, which include the requirement to "plan, construct, operate and maintain the system in accordance with good utility practice." Section 31.6 defines the requirement for network customers to supply annual load and resource updates ("L&Rs") for inclusion in planning studies.

The Company solicits each of its network customers for L&R data annually in order to determine future load and resource requirements for all transmission network customers. These customers include PacifiCorp Energy (which serves PacifiCorp's retail customers and comprises the bulk of the Company's transmission network customer needs), Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative, Bonneville Power Administration, Basin Electric Power Cooperative, and Moon Lake Electric Association.

The Company uses its customers' L&Rs and best available information to determine project need and investment timing. In the event that customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios for its project investment as appropriate.

Reliability

PacifiCorp's transmission network is required to meet increasingly stringent mandatory Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) reliability standards, which require infrastructure sufficient to withstand unplanned outage events. Compliance with NERC planning standards is required of the NERC Regional Councils and their members, as well as all other electric industry participants if the reliability of the interconnected bulk electric systems is to be maintained in the competitive electricity environment. The majority of these mandatory standards are the responsibility of the transmission owner.

NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities in order to meet NERC reliability criteria.

Transmission system designs require the ability to recover from system disturbances that impact main grid transmission. Designs often require accommodating multiple contingency scenarios, which Energy Gateway helps facilitate along with other system reinforcement projects. A number of main grid transmission outages occurred in the latter part of 2007, resulting in curtailment of schedules, curtailments of interruptible loads and generation curtailments. These outages occurred on main grid paths and the lack of transmission capacity severely limited available mitigation measures for system recovery.

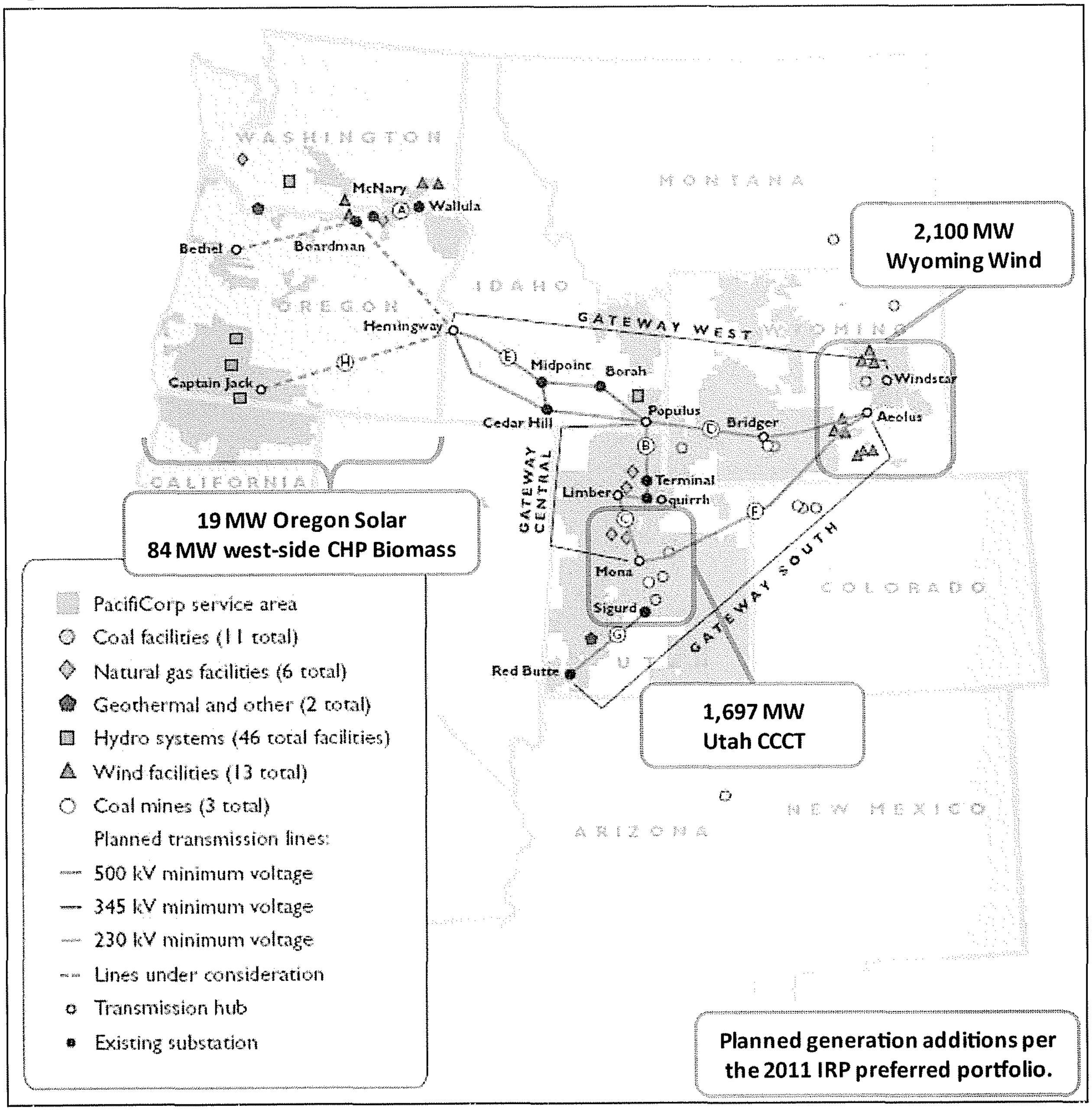
Resource Locations

PacifiCorp's primary energy resources are located in Utah, Wyoming, desert southwest and the west. Energy Gateway leverages PacifiCorp's diverse mix of energy resources at key locations throughout its service territory. As an extension of Energy Gateway's 'hub and spoke' strategy, PacifiCorp must consider logical resource locations for the long-term based on environmental constraints, economical generation resources, and federal and state energy policies. Energy

Gateway's design and extensive footprint support the development of a diverse range of cost-effective resources required for meeting customer energy needs.

Figure 4.4 below shows PacifiCorp's service territories and owned generation with an overlay of the Energy Gateway Transmission Expansion Plan. Also noted are the planned generation additions per the 2011 IRP preferred portfolio. New transmission capacity is required to deliver these energy resources to customers. The *Transmission Scenario Analysis* section provides an in-depth comparison of different energy futures and how varying Energy Gateway segment combinations impact PacifiCorp's 20 year present value revenue requirement.

Figure 4.4 – PacifiCorp service territory, owned generation and Energy Gateway overlay[25]



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

[25] Visit PacifiCorp's Energy Gateway website for maps of renewable energy potential in the Western U.S. as provided by the National Renewable Energy Laboratory (NREL), including Energy Gateway overlays:

- Wind: http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/WindPowerPotential.10.pdf
- Solar: http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/SolarPotential.10.pdf
- Geothermal: http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/GeothermalPotential.10.pdf
- Biomass: http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/BiomassPotential.10.pdf

Energy Gateway Priorities

Major segments of the Energy Gateway project originate in Wyoming and Utah and migrate west to Oregon and Idaho. The Energy Gateway project takes into account the existing 2006 MidAmerican Energy Holdings Company transaction commitments relating to transmission system improvements between southeast Idaho and northern Utah (Populus to Terminal), within Utah's Wasatch Front (Mona to Oquirrh), and the Northwest's Mid-C area (Walla Walla to McNary).

PacifiCorp is actively pursuing the Energy Gateway transmission project under the following overarching key objectives:

- **Customer driven** – Energy Gateway is driven by PacifiCorp's retail, wholesale and network customers' needs. Including Energy Gateway as a base allows PacifiCorp to move forward with the knowledge that over the coming years, transmission lines will be utilized to their fullest potential.
- **Support multiple resource scenarios** – The transmission expansion project will accommodate a variety of future resource scenarios, including meeting renewable and low-carbon generation requirements, supporting natural gas fueled combustion turbines and market purchases, and recognizing that clean coal-based generation may emerge as a viable resource.
- **Consistent with past and current regional plans** – The proposed projects are consistent with numerous regional planning efforts. The need to expand transmission capacity has been known for years and is increasing due to substantial variable resource additions to the system.
- **Get it built** – Transitioning from planning to implementation is key to achieving "steel in the ground" and meeting customer needs. Proactive engagement with stakeholders and policymakers in the planning process will help minimize barriers to implementation.
- **Secure the support of state and federal utility commissions for rate recovery** – PacifiCorp will continue to seek the input of state and federal regulators throughout the planning process to ensure concerns are communicated and addressed early.
- **Protect the investment to the benefit of customers** – An appropriate balance must be struck to ensure that network customers do not subsidize third party use and to ensure that PacifiCorp's long-term network allocation requirements are retained.

"Rightsizing" Energy Gateway

PacifiCorp's priority in building Energy Gateway is to meet the needs of its customers. The Company requires new transmission capacity to adequately serve its customers' load and growth needs across the next 20 year horizon and beyond. Recognizing the potential regional benefits of "upsizing" the project (such as maximized use of energy corridors, reduced environmental impacts and improved economies of scale), the Company included in its original Energy Gateway plan the potential for doubling the project's capacity to encourage third-party commitments and equity partnerships necessary to support such an investment. In the years since the May 2007 announcement of Energy Gateway, the Company has pursued such partnerships but due to the significant costs inherent in transmission investments – and the Company's obligation to shelter its customers from costs and risks associated with "upsizing" the project for third-parties' benefit – these commitments have not materialized. PacifiCorp is committed to building Energy Gateway to meet the needs of its customers and is moving ahead with the appropriate investments to do so.

The core transmission expansion plan includes lines and stations required to deliver additional transmission capacity required to meet PacifiCorp's long-term regulatory requirement to serve loads. Each segment will be justified individually within the overall program. A combination of benefits, including net power cost savings derived from the IRP, reliability, capital offsets for renewable resource development in low yield geographic regions and system loss reductions will be used to assess the viability of each segment. See the *Transmission Scenario Analysis* section below.

Each Energy Gateway segment will be re-evaluated during the Company's annual business plan and IRP cycles to ensure optimal benefits and timing before moving forward with permitting and construction. Depending on conditions or alternatives, certain segments could be deferred or not constructed if evaluations prove the need or timing has shifted. PacifiCorp also evaluates joint development opportunities with other utilities and transmission developers where appropriate to minimize cost and impacts while providing necessary benefits to customers. See Chapter 10 – Transmission Expansion Action Plan, for more information on Energy Gateway and joint development opportunities.

WECC Ratings Process

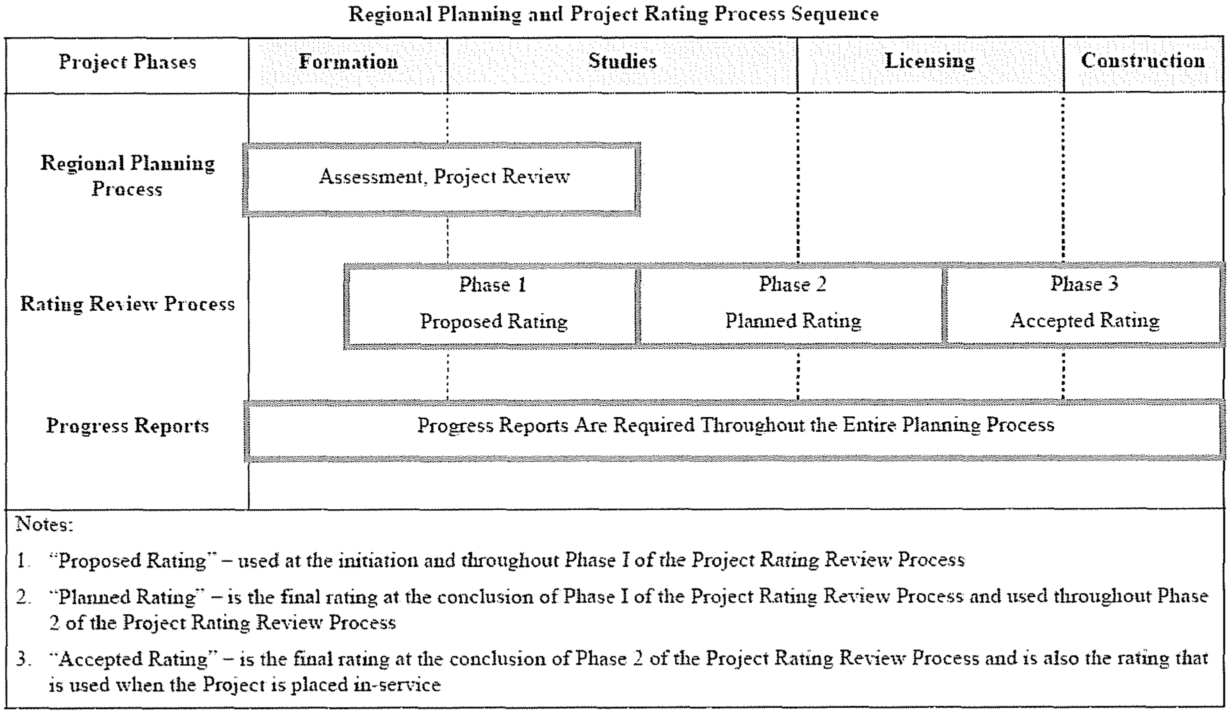
The Western Electricity Coordinating Council ("WECC") provides a formal process for project sponsors to achieve a WECC Accepted Rating and demonstrate how their project will meet the related NERC and WECC Planning Standards. This process requires close coordination between the project sponsor(s) and representatives of other transmission systems that may be impacted by the proposed project. Figure 4.5 below shows the stages of the WECC rating process, and a high-level summary of the 3-phase process is provided here:

- Phase 1: The project sponsor conducts studies to demonstrate the proposed rating of the project and prepares a Comprehensive Progress Report documenting study results and project details. Once the progress report is accepted by WECC, the project is granted a "Planned Ratting" and Phase 1 is considered complete.

- Phase 2: A review group comprised of interested WECC members conducts a thorough review of the project, validating its planned rating and further assessing its simultaneous transfer capability and impacts on neighboring transmission systems. All studies and findings in this phase are documented in a Phase 2 Rating Report. Once this report is accepted by WECC, the project is granted an "Accepted Rating" and Phase 2 is considered complete.

- Phase 3: Major changes in project assumptions and system conditions are evaluated to ensure the Accepted Rating is maintained. Phase 3 is completed when the project is placed into service.

Figure 4.5 – Stages of the WECC Ratings Process



Source: WECC Overview of Policies and Procedures for Regional Planning Project Review, Project Rating Review, and Progress Reports (Revised by RPPTF 01/19/2005) http://www.wecc.biz/Documents/2005/PCC%20Meetings/Policies_Procedures_01-19-05_version_clean_v1.pdf

Since the initial May 2007 announcement of Energy Gateway, PacifiCorp has made significant progress through the extensive WECC ratings process. PacifiCorp initiated the process for Energy Gateway West and Energy Gateway South in June 2007. Phase 1 Comprehensive Progress Reports were issued in November 2008 and, following a 60-day review period, both projects were granted Phase 2 status in February 2009.

The following is a list of Energy Gateway transmission paths that have completed the Phase 2 process and have been granted Phase 3 Status:

- Energy Gateway West
  - TOT 4A – December 2010
  - Aeolus West – January 2011
  - Bridger/Anticline West – January 2011
  - Path C – January 2011
- Energy Gateway South
  - Aeolus South – December 2010

Additional paths for each project are nearing completion of Phase 2, including Borah West and Midpoint West (Gateway West), and TOT 2B/C (Gateway South). Upon WECC's granting of

Phase 3 status, WECC recognizes the capacity ratings of these transmission paths to a similar extent as a completed project.[26]

Regulatory Acknowledgement and Support

Beyond the extensive list of planning efforts discussed in this section—the joint initiatives, rating studies, federal and state policy directives, system reliability requirements, and all the other considerations that are factored into transmission planning—*regulatory support* is critically important to these investments materializing. Also, timely permitting by agencies is important for these investments to be available to meet PacifiCorp's need to serve load.

PacifiCorp provides electric service across six western states through an expansive integrated system of generation and transmission facilities necessary to serving its customers. System maintenance, reinforcements and additions are fundamental to the Company's ability to provide reliable service. Likewise, cost recovery for prudent investments is fundamental to the Company's ability to continue making these necessary investments on behalf of its customers. PacifiCorp will seek fair valuation and cost recovery for all of its Energy Gateway investments to ensure customers pay for an appropriately balanced share of these facilities.

By June 1, 2011, PacifiCorp will file a transmission rate case with the Federal Energy Regulatory Commission ("FERC") to update the service rates in its FERC-approved Open Access Transmission Tariff ("OATT"). The Company will seek updated rates that appropriately reflect the transmission investments made since its last FERC rate case in the 1990s. The OATT rates set by FERC apply to wholesale and third-party customer transmission transactions. Since it is PacifiCorp's retail customers who will pay for the Energy Gateway investments, the revenues from wholesale and third-party transmission sales are a dollar-for-dollar offset to retail customers' rates.

PacifiCorp has already begun seeking state regulatory approval and cost recovery for its Energy Gateway investments, which to date consist primarily of the Populus to Terminal project completed in November 2010. A fair valuation of these investments by each state commission means PacifiCorp's retail customers in each of the states it serves will pay an appropriate allocation of these costs and no more. However, regulatory challenges and disallowances in one state upsets this balance, resulting in customers in one state paying more than customers in another state, or in PacifiCorp under-recovering for the prudent investments it has made—or both.

PacifiCorp will continue to work with its state and federal regulators to demonstrate the prudence of the Company's investments and to ensure an equitable cost-balance among all of its customers.

[26] For complete details on all WECC rated transmission paths, see the WECC 2011 Path Rating Catalog available at www.wecc.biz (click "Quick Links" and choose "Path Rating Catalog)

Transmission Scenario Analysis

Additional Transmission Scenarios

The 2008 IRP included background information on Energy Gateway resulting from various regional planning studies and the Company's responsibility for interconnection-wide transmission planning under the Federal Energy Regulatory Commission's Order 890. Specifically, several planning studies dating back to September 2004 identified the critical need to alleviate transmission congestion and move transmission constrained energy resources to Company load centers. The 2008 Energy Gateway strategy outlined the overarching key objectives and action plan to construct the proposed transmission segments between 2010 and 2019. The Populus to Terminal segment identified for 2010 completion has been placed in-service and is providing additional transmission capacity as planned.

Feedback on the 2008 IRP from various stakeholders requested additional transmission analysis to be undertaken that would examine different deployment scenarios based on a variety of input assumptions. In 2010, the Company undertook a transmission sensitivity analysis that involved variations of the Energy Gateway transmission footprint, timing of in-service dates, megawatt capacity, future loads, energy resources and drivers that influence energy resources as well as the need for transmission. Previous analysis focused on an all-inclusive Energy Gateway scenario compared to a "no-Gateway" scenario where variable production cost savings and least-cost construction estimates were the basis of the recommendation to move forward. The 2010 Energy Gateway analysis undertook a broader approach to the Energy Gateway strategy by determining if constructing all or parts of the transmission segments is in the best interest of customers.

Two underlying strategies emerged regarding renewable resources and the need for additional transmission.

Green Resource Future

This outlook assumes that federal and state governments continue a 'green' resource strategy that optimizes renewable resources as a significant energy source and reduces carbon emissions. The outlook also assumes the United States takes an aggressive role in accelerating renewable resources through incentives, CO_2 taxes or renewable targets. Demand for energy experiences a significant increase through renewed economic growth and the higher penetration of electric applications such as electric vehicles. Alternate resource technologies continue to be developed but the mainstay of renewable energy resources for the next twenty years is wind located in areas that offer economic and political acceptance.

Incumbent Resource Future

This scenario assumes carbon legislation and federal/state renewable energy requirements will subside, thereby lessening the demand for renewable resources and where they are placed. This scenario ignores natural gas price volatility and assumes stable natural gas prices which diminish the need for large wind resource additions and transmission projects originating in Wyoming over the next twenty years. Lower gas prices translate to serving loads with gas turbines located closer to Company load centers such as Utah. Alternate energy technologies such as electricity storage, battery and smart grid technologies will be developed, but the majority of new energy is generated from existing fuel resources.

2011 IRP Transmission Analysis

Seven Energy Gateway scenarios were initially selected and modeled using the Company's System Optimizer capacity expansion tool. These scenarios ranged from a "base case" scenario with minimal planned transmission (including the Populus to Terminal, Mona to Oquirrh and Sigurd to Red Butte[27] projects) to the full "incremental" Energy Gateway strategy (including Energy Gateway West, Aeolus to Mona and west-side projects). With a combination of alternative renewable portfolio standard and CO_2/gas price assumptions these scenarios reflect the key elements of the Green Resource and Incumbent Resource futures, although specific assumptions such as increased electric vehicle applications were not modeled for the 2011 IRP. The scenarios represent the most logical combination of transmission segments to move energy from resource centers to regional Company load centers including timing of in-service dates and subsequent incremental transmission capacity.

Incremental transmission capacity became very dynamic in some scenarios due to certain transmission segments providing redundant/contingency back-up and therefore resulting in higher incremental capacity ratings compared to transmission segments without redundancy. Less than full incremental transmission path ratings were assumed for some segments when modeling incremental capacity without redundancy, which translated to almost half the designed capacity rating.

The System Optimizer can solve simultaneously for resources and transmission expansion; however a limitation of the model occurs when one transmission option is dependent on another, such as for ratings support. Such "contingent" optimization required 'fixed' transmission configurations utilizing multiple transmission scenarios rather than have the model optimize transmission expansion options independently.

Figures 4.6 to 4.12 show maps of the seven System Optimizer scenarios for Energy Gateway Transmission. (Refer to Chapter 10 – Transmission Expansion Action Plan, for detailed descriptions of each of the planned Energy Gateway segments.) The 'base case' scenario (Scenario 1) is a minimum-build transmission plan that is also part of the Energy Gateway strategy; however, it needs to be constructed regardless of other Energy Gateway options due to specific load and reliability requirements. PacifiCorp is also committed to pursuing the

[27] The Utah Public Service Commission (Docket No. 09-2035-01, April 1, 2010) directed the Company to "omit from its core cases any resource for which it does not already have a signed final procurement contract or certificate of public convenience and necessity." Each of the Energy Gateway segments in the Company's base case (Scenario 1) has received a CPCN with the exception of the Sigurd to Red Butte project. Sigurd to Red Butte, like the other base-case projects, is part of the Company's minimum-build transmission plan based on need for these specific projects among studied alternatives. The CPCN filing for this project is imminent and its scheduled in-service date is consistent with the in-service date range of other base case projects (2012-2014) for which the Company requests acknowledgement in this IRP.

incremental additions of Energy Gateway and is permitting each segment based on what the Company believes is needed for customers. PacifiCorp and its stakeholders will continue to have opportunity to evaluate that need as some of the policy uncertainties are addressed in the coming years and before reaching "steel-in-the-ground" on these incremental additions.

Figure 4.6 – System Optimizer Energy Gateway Scenario 1

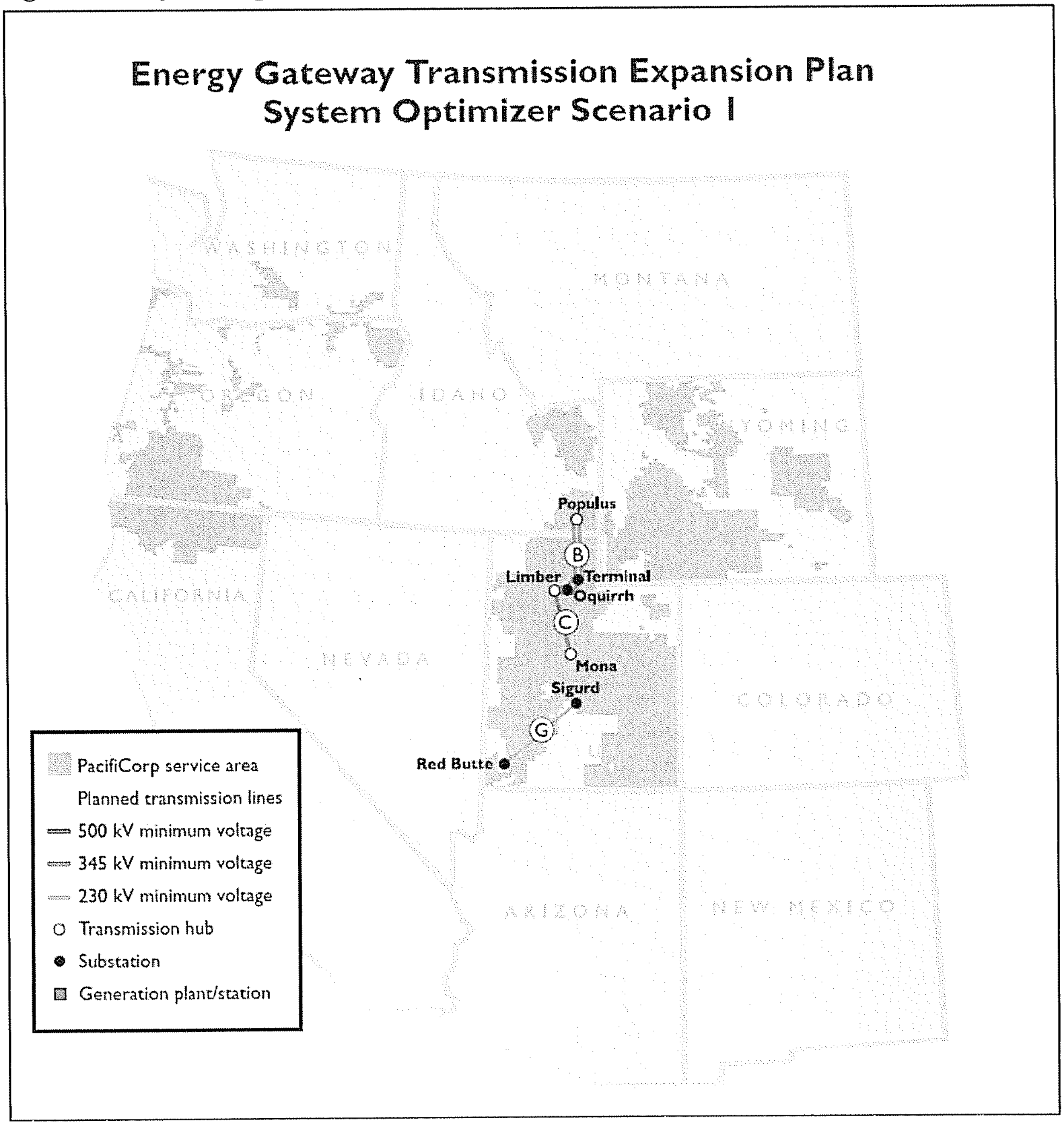


Figure 4.7 – System Optimizer Energy Gateway Scenario 2

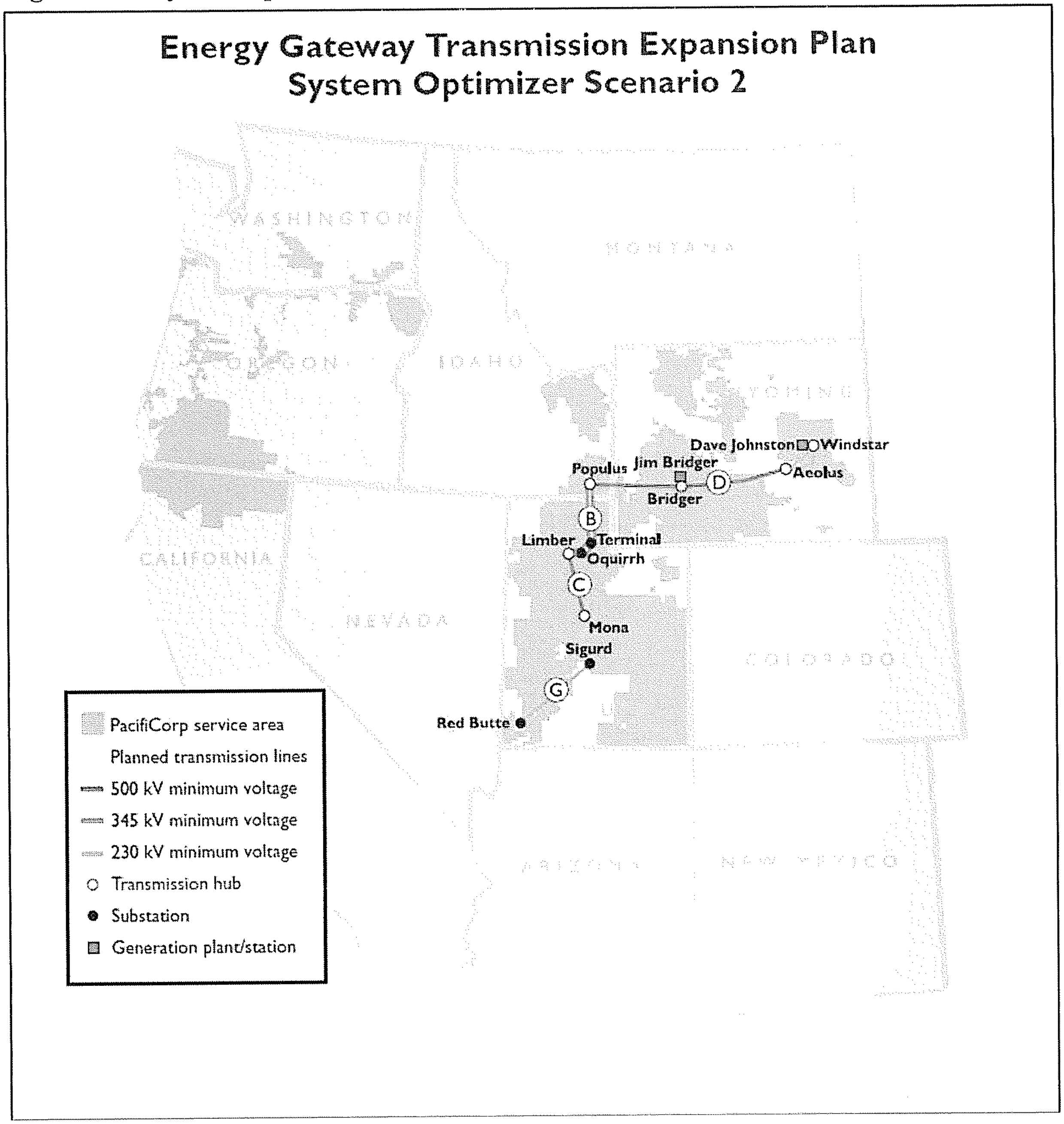


Figure 4.8 – System Optimizer Energy Gateway Scenario 3

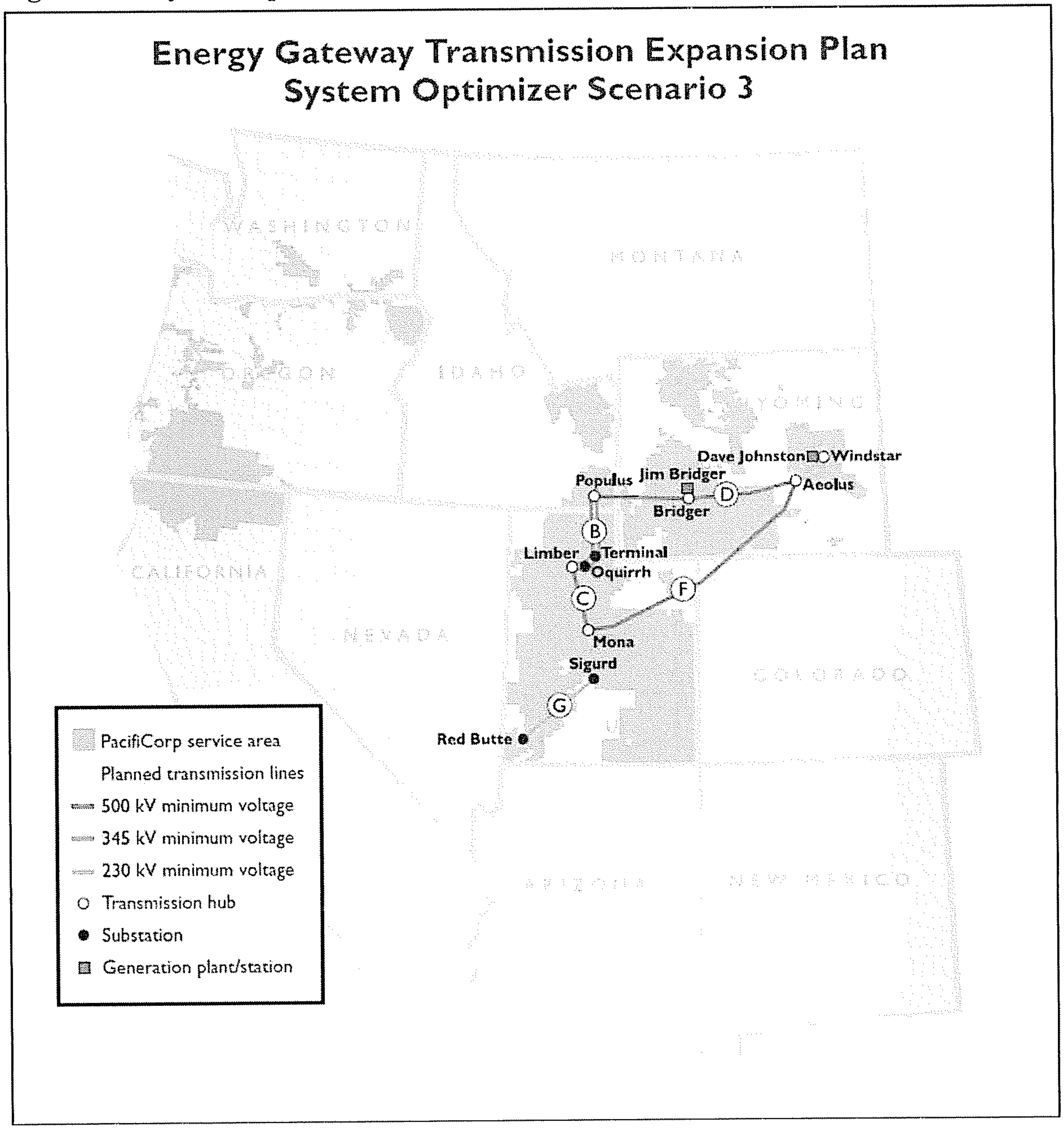


Figure 4.9 – System Optimizer Energy Gateway Scenario 4

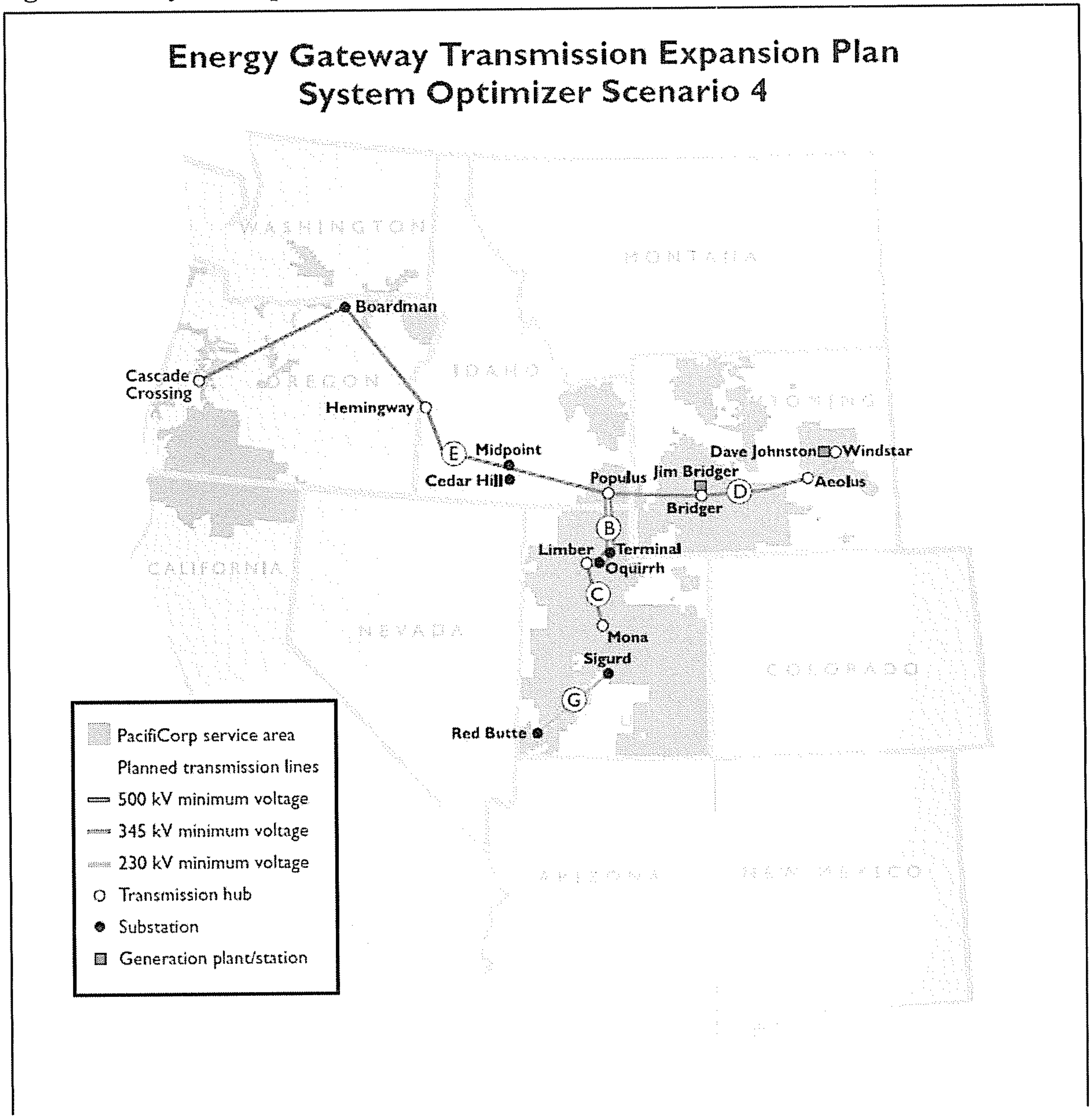


Figure 4.10 – System Optimizer Energy Gateway Scenario 5

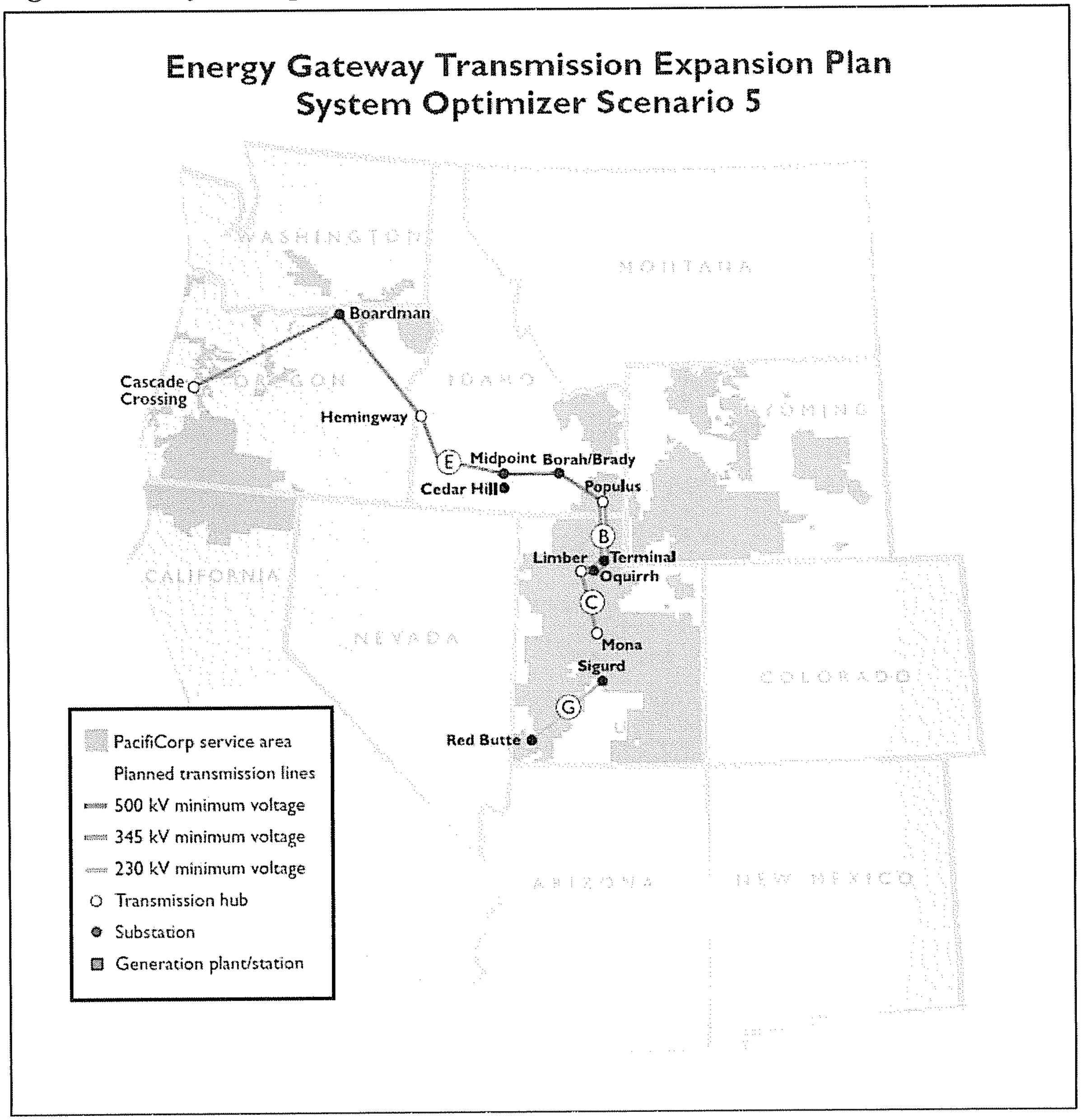


Figure 4.11 – System Optimizer Energy Gateway Scenario 6

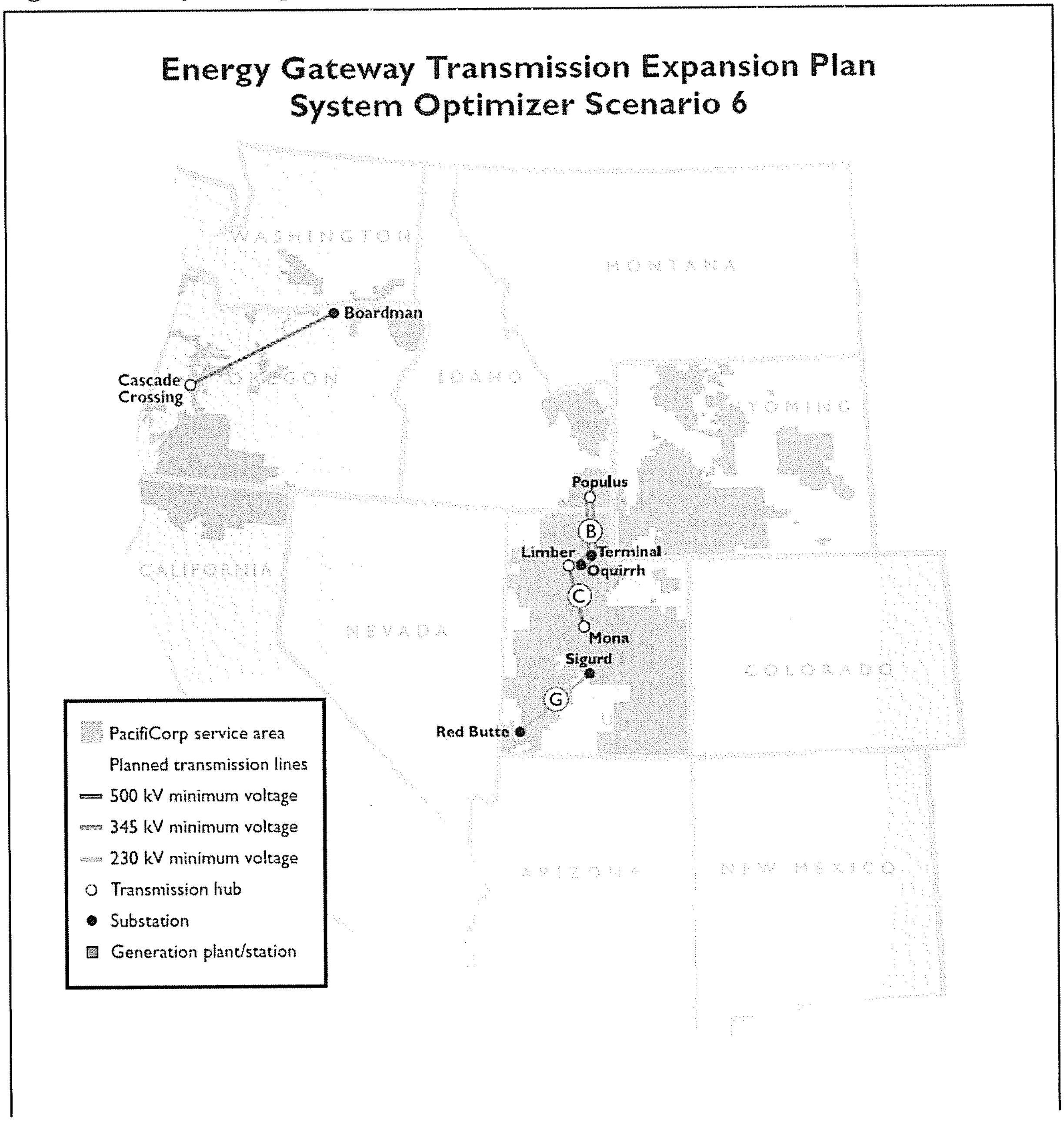
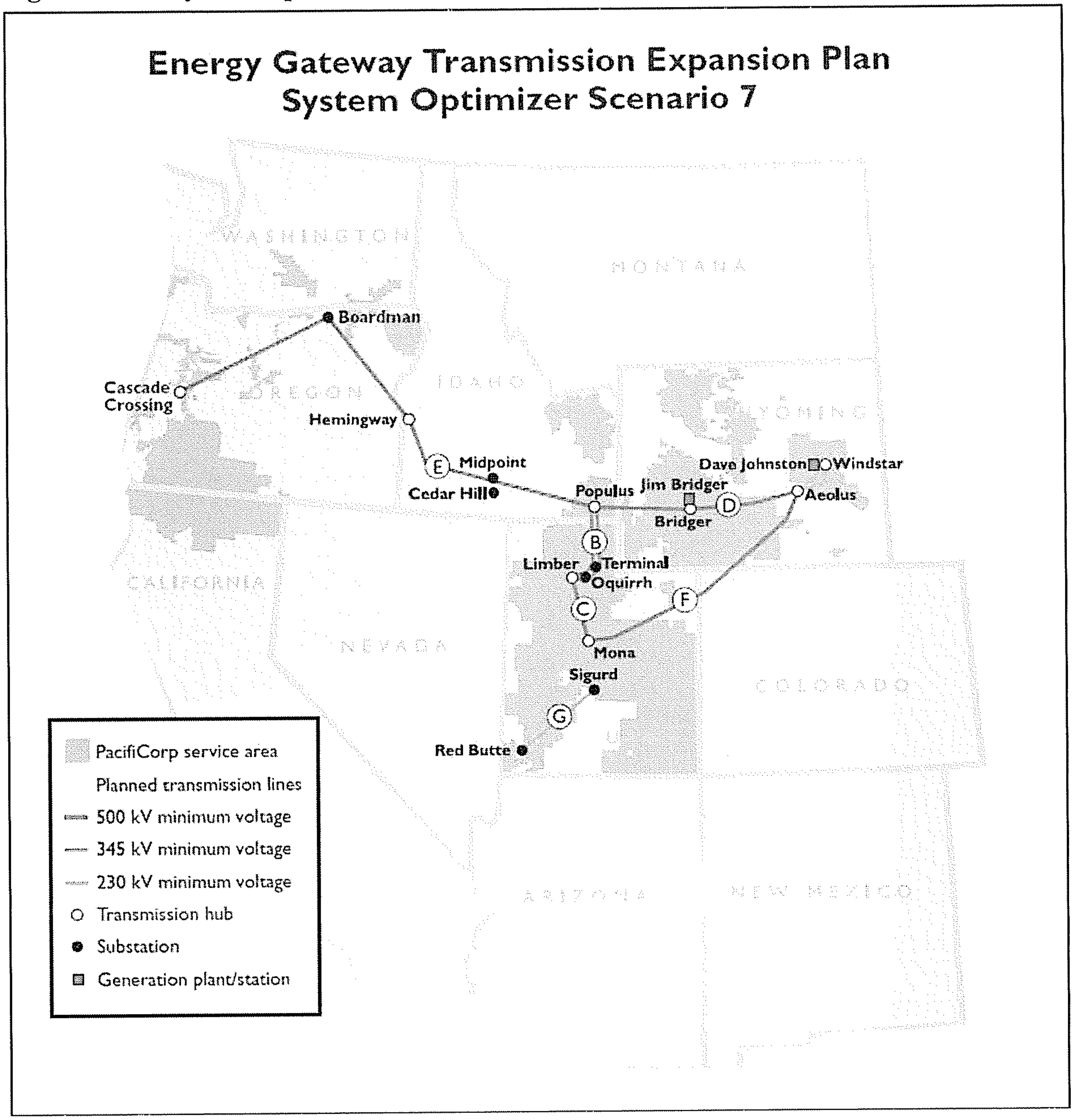


Figure 4.12 – System Optimizer Energy Gateway Scenario 7



System Optimizer Assumptions

The placement of wind, if selected as a resource, was facilitated by incremental transmission capacity. The System Optimizer placed wind resources in the most cost-effective locations considering available transmission. Without available transmission, the model placed wind resources, if economic, in alternative wind generation bubbles outside of the Energy Gateway scenarios. See Chapter 6 for treatment of wind resources and supporting transmission costs, and Chapter 7 for a detailed description of the Energy Gateway scenario specification and the System Optimizer modeling methodology.

The System Optimizer uses the capacity contribution of resources at the time of system peak to determine the capacity expansion plan that meets the planning reserve margin constraint. In the case of intermittent resources with relatively variable capacity contributions, the nominal capacity added by the model can exceed available transmission capacity for certain hours where the intermittent resource is operating near maximum capacity.

A set of four CO_2 tax and natural gas price combinations were assumed in the modeling: medium CO_2 tax/medium gas price, medium CO_2 tax/high gas price, high CO_2 tax/ medium gas price and high CO_2 tax/high gas price for transmission scenarios. The range of CO_2 taxes and natural gas cost values are described in Chapter 7.

While the System Optimizer selects resources based on certain assumptions using deterministic loads and resources, it does not model stochastic risk which is done through the Planning and Risk (PaR) model as described in Chapter 7.

The System Optimizer does not take into account all transmission operating requirements or limitations such as Remedial Action Schemes (RAS), which manage automatic protection systems designed to detect abnormal or predetermined system conditions and take corrective actions in order to maintain system reliability. Placement of additional resources cannot expose the network to abnormal RAS risks. In one scenario, wind had to be moved to a different location due to lack of transmission capacity.

A 20 year present value revenue requirement (PVRR) was calculated for each Energy Gateway scenario by including fixed and variable costs for the resource portfolios. The Energy Gateway scenarios with the lowest PVRR represent the least cost solution as calculated by the System Optimizer. A full financial analysis requires the System Optimizer resource selection to be run through the PaR model for stochastic calculations of probabilistic outcomes to measure risk (loads, market prices, gas prices, hydro availability, and forced outages).

Output from initial transmission scenario uploads in the System Optimizer eliminated three scenarios for various reasons. Scenario 6, which added Boardman – Cascade Crossing to the base-case, was eliminated from further analysis at this time because the System Optimizer topology in the West was not detailed enough to calculate credible results. Scenario 5, which added Populus – Boardman – Cascade Crossing to the base-case, was eliminated from further analysis given the difference between scenario 7 and scenario 3 would isolate the value of Scenario 5. Scenario 4, which added Windstar – Populus – Boardman – Cascade Crossing to the base-case, was eliminated because the placement of wind resources was identical to Scenario 2 and it did not make sense to consider additional transmission costs from Populus – Boardman – Cascade Crossing.

Green Resource Future Results

The Green Resource Future included a set of System Optimizer runs to reflect planning assumptions favorable to more wind development along with the four combinations of CO_2 and natural gas prices.

Federal renewable energy requirements were assumed at the Waxman-Markey level (20 percent by 2020). The Company limited geothermal resource selection to the Blundell site in Utah at 80 MWs due to uncertainty regarding the prospects for geothermal development and cost recovery in PacifiCorp's other state jurisdictions.[28] This resulted in wind selection more in line with the wind amounts in the preferred portfolios for the 2008 IRP and 2008 IRP Update.

PacifiCorp also adjusted import capacities for the Goshen and Yakima topology bubbles. The adjustments eliminated capacity deficits in these bubbles caused by transmission constraints. These transmission constraints are a function of model behavior and not indicative of any real transmission constraints for these areas of the system. Relieving these "artificial" transmission constraints improved the economics of Scenario 1 relative to the other segment scenarios. The other scenarios were not affected by the topology changes because the incremental transmission segments they reflected, such as Windstar-Populus, relieved the constraints as well.

The System Optimizer selection of wind resources under the Green Resource Future are summarized in Table 4.1. Note that the scenario identification numbers 1, 2, 3, and 7, were renumbered to base, 1, 2, and 3 for presentation in public IRP documents. This modified labeling convention is used for the rest of the IRP document.

In all cases, wind was a significant resource pick primarily based on the renewable resource requirement. Variations between resource locations and megawatt totals were based on economics and available transmission. In transmission Scenario 1 for instance, the System Optimizer assigned a significant amount of wind resources in Washington since there was no transmission path between east and west. Given that the incremental megawatts for wind exceeded current transmission capacity, additional transmission facilities had to be incorporated into the present value revenue requirement for Scenario 1.

Similar logic was applied to Scenario 2 where the System Optimizer assigned significant wind resources in Wyoming, but lack of transmission capacity and RAS risks required the wind to be moved, with additional transmission facilities.

The wind resources picked under this set of sensitivities are similar to the resources shown in the 2008 IRP Update.

The System Optimizer 20-year PVRR results from the Green Resource Future analysis are summarized in Table 4.2. Definitions for the System Optimizer cost categories are as follows:

- Station Costs: Represents the PVRR cost for fuel, variable operation and maintenance, fixed costs, emissions, decommissioning, and investment capital recovery for existing and new power stations. Stations are generally defined as resources that are not contracted
- Transmission Costs: Represents the PVRR cost for the specified Energy Gateway scenario plus the capital recovery for any transmission additions required to support location dependent resources. Wheeling costs are also included.

[28] While Utah geothermal resources were allowed for this scenario analysis, the Company anticipates legislative and regulatory actions to address cost recovery and resource pre-approval concerns before geothermal acquisition is pursued as a resource strategy. This issue is discussed in Chapters 8 and 9.

- DSM Costs: Represents the PVRR cost for existing and new demand-side management programs and measures. Costs include energy, capacity, and the recovery of capital investment.
- Contract Costs: Represents the PVRR cost for existing Company power supply contracts. Costs include energy and capacity portion of contracts. These costs remain static between portfolios.
- Spot Market Net Purchases/Sales: Represents the net PVRR cost of spot market transactions (purchases and sales) at the market hubs. The cost is a function of the megawatt volume sold or purchased and the forward prices assigned to the market hubs.
- Unserved Energy: Represents the penalty cost of not meeting the planning reserve margin (unserved capacity) as well as the penalty cost of any energy not able to be served. The unit penalty costs are set to $9 million per MW-month for unmet capacity, and $5,000 per MWh for unserved energy. These values are set sufficiently high to prevent System Optimizer from generating unmet energy and capacity as a means to lower PVRR.

Table 4.1 – Green Resource Future, Selected Wind Resources (Megawatts)[29]

Transmission Scenario	Scenario 1	Scenario 2[30]	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Renewable Assumption	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman
Wind-ID	200				172			
Wind-UT	500				500			
Wind-WY	2	1,178	1,205	1,229	2	1,156	1,180	1,207
Wind-WA	816	173	173	173	872	200	200	200
Wind-OR	86				56			
Total Wind	**1,604**	**1,351**	**1,379**	**1,402**	**1,602**	**1,356**	**1,380**	**1,407**

Transmission Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	High	High	High	High	High	High	High	High
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Renewable Assumption	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman
Wind-ID	200				146			
Wind-UT	529	72			500	84		
Wind-WY	2	1,184	1,246	1,246	2	1,172	1,620	1,960
Wind-WA	871	200	200	200	1,021	200	200	200
Wind-OR								
Total Wind	**1,602**	**1,457**	**1,446**	**1,446**	**1,669**	**1,456**	**1,820**	**2,160**

[29] See Appendix C for detailed resource portfolio tables.

[30] Scenario 2 calls for up to 1,184 MW of incremental Wyoming wind, however present value revenue requirements reflect added transmission to accommodate a portion of wind resource moved to Utah. Scenario 2 will not support 1,184 MW of additional wind in Wyoming due to transmission constraints and operational requirements.

Table 4.2 – Green Resource Future, Present Value Revenue Requirement ($ millions)

Transmission Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Renewable Assumption	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman
Station Costs	37,934	37,395	37,394	37,393	40,171	39,511	39,509	39,509
Transmission Costs[31]	3,103	2,499	2,524	2,564	3,103	2,499	2,524	2,563
DSM Costs	2,528	2,549	2,549	2,549	2,660	2,669	2,669	2,669
Contract Costs	3,294	3,294	3,294	3,294	3,303	3,303	3,303	3,303
Spot Market, Net Purchase / Sales	(5,121)	(4,890)	(4,891)	(4,890)	(6,544)	(6,186)	(6,185)	(6,186)
Unserved Energy	0	0	0	0	0	0	0	0
Total PVRR Costs	**$41,739**	**$40,847**	**$40,870**	**$40,909**	**$42,693**	**$41,797**	**$41,821**	**$41,859**
Difference to Scenario 1	**$0**	**($892)**	**($869)**	**($830)**	**$0**	**($896)**	**($872)**	**($834)**
Transmission Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	High	High	High	High	High	High	High	High
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Renewable Assumption	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman	Waxman
Station Costs	42,794	42,082	42,078	42,075	45,601	44,736	44,611	44,630
Transmission Costs	3,103	2,499	2,524	2,563	3,104	2,500	2,525	2,564
DSM Costs	2,598	2,705	2,705	2,705	2,693	2,752	2,753	2,752
Contract Costs	3,299	3,299	3,299	3,299	3,302	3,302	3,302	3,302
Spot Market, Net Purchase / Sales	(5,089)	(4,792)	(4,792)	(4,790)	(7,008)	(6,514)	(6,439)	(6,464)
Unserved Energy	0	0	0	0	0	0	0	0
Total PVRR Costs	**$46,706**	**$45,793**	**$45,815**	**$45,854**	**$47,691**	**$46,775**	**$46,752**	**$46,784**
Difference to Scenario 1	**$0**	**($913)**	**($891)**	**($852)**	**$0**	**($916)**	**($939)**	**($907)**

[31] Represents the present value revenue requirement (PVRR) for the specified Energy Gateway scenario plus any capital recovery of transmission additions required to support location dependent resources. Scenario 7 represents the full Energy Gateway expansion plan, which is an approximately $6 billion investment plan. This investment is amortized over a 58-year period, but for consistency with the IRP's 20-year scope, only 20 years of the total amortized cost is provided here. See Appendix C for a detailed Transmission PVRR cost table.

The System Optimizer PVRR results are a 20-year deterministic view of resources and portfolio costs. In order to assess the stochastic PVRR results, the resource selection must be run through the Planning and Risk model for a complete cost assessment. However, a 'base-case' Scenario 1 development plan is clearly more expensive when compared to the alternatives. Stochastic production cost evaluation of these Energy Gateway scenarios, or new ones as dictated by the planning environment, is expected to be performed before the final 2011 IRP update is issued.

Incumbent Resource Future Results

A series of System Optimizer runs were initiated assuming the same range of CO_2 taxes and natural gas costs used in the Green Resource Future. The Energy Gateway scenarios were also repeated along with the assumption for production tax credits. Renewable requirements were established to meet current state requirements on a system basis, which also satisfies Senator Bingaman's proposed federal targets of 9 percent by 2021 and 15 percent by 2025 for all scenarios.

The Incumbent Resource Future results for wind resources produced much lower MWs compared to the Green Resource Future due to the lower renewable requirements, lack of a production tax credit after 2014, and displacement by geothermal resources.[32] Unlike the Green Resource Future, the Company assumed no limitations in terms of geothermal resource selection on a regional basis. Also, the model topology does not reflect transmission capacity adjustments for the Yakima and Goshen topology bubbles discussed above. Wind became the selected resource in high CO_2 tax/ high gas price scenarios due to economics, but was not selected in other pricing scenarios. For scenarios with high natural gas costs, the System Optimizer selected several hundred megawatts of geothermal in the west.

Wind resources for the Incumbent Resource Future analysis are summarized in Table 4.3. Complete resource portfolio tables are provided in Appendix C.

In all cases, except when CO_2 taxes and natural gas prices were high, the System Optimizer did not pick wind resources. Only with the combination of high CO_2 and natural gas prices did the System Optimizer select wind in Wyoming. A high CO_2 tax and a renewable standard could be contradictory in actual practice.

The System Optimizer 20-year PVRR results from the Incumbent Resource Future analysis are summarized in Table 4.4.

[32] The December 2010 model runs incorporated updated geothermal resource potentials and cost information from a consultant study. As noted in Chapter 9, uncertainty regarding whether geothermal development costs for specific resources can be recovered is currently the most significant resource risk.

Table 4.3 – Incumbent Resource Future, Selected Wind Resources (Megawatts)

Transmission Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Renewable Assumption	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman
Wind-ID								
Wind-UT								
Wind-WY	2	52	52	76				
Wind-WA	56				100	100	100	100
Wind-OR								
Total Wind	**58**	**52**	**52**	**76**	**100**	**100**	**100**	**100**
Transmission Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	High	High	High	High	High	High	High	High
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Renewable Assumption	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman
Wind-ID								
Wind-UT	4							
Wind-WY	2	47	47	72	1,157	1,157	1,563	1,948
Wind-WA	2				200	200	200	200
Wind-OR								
Total Wind	**8**	**47**	**47**	**72**	**1,357**	**1,357**	**1,763**	**2,148**

Table 4.4 – Incumbent Resource Future, Present Value Revenue Requirement ($ millions)

Transmission Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Renewable Assumption	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman
Station Costs	36,472	36,457	36,457	36,491	38,939	38,997	38,997	38,970
Trans Costs	1,458	1,916	2,419	2,518	1,456	1,915	2,418	2,517
DSM Costs	3,486	3,486	3,486	2,600	3,870	3,796	3,796	2,892
Contract Costs	3,294	3,294	3,294	3,294	3,303	3,303	3,303	3,303
Spot Market, Net Purchase / Sales	(4,622)	(4,624)	(4,624)	(4,598)	(6,284)	(6,339)	(6,339)	(6,179)
Unserved Energy	702	702	702	196	607	607	607	152
Total PVRR Costs	**$40,789**	**$41,232**	**$41,734**	**$40,501**	**$41,890**	**$42,278**	**$42,781**	**$41,656**
Difference to Scenario 1	**$0**	**$443**	**$945**	**($288)**	**0**	**$388**	**$891**	**($234)**
Transmission Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	High	High	High	High	High	High	High	High
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Renewable Assumption	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman	Current State RPS/ Bingaman
Station Costs	41,408	41,293	41,287	41,353	44,355	44,427	43,591	44,485
Transmission Costs	1,457	1,916	2,419	2,518	1,601	2,500	2,525	2,564
DSM Costs	3,550	3,553	3,553	2,695	3,800	3,768	3,958	2,845
Contract Costs	3,299	3,299	3,299	3,299	3,302	3,302	3,302	3,302
Spot Market, Net Purchase / Sales	(4,596)	(4,502)	(4,497)	(4,503)	(6,723)	(6,867)	(6,924)	(6,768)
Unserved Energy	701	701	701	196	607	607	722	152
Total PVRR Costs	**$45,820**	**$46,261**	**$46,763**	**$45,558**	**$46,941**	**$47,737**	**$47,174**	**$46,581**
Difference to Scenario 1	**$0**	**$261**	**$943**	**($262)**	**$0**	**$796**	**$233**	**($360)**

The System Optimizer 20-year PVRRs for Scenarios 2 and 3 were higher than the base-case Scenario 1. The full Energy Gateway strategy, Scenario 7, was less costly than base-case Scenario 1. However, if the import capabilities for Goshen and Yakima topology bubbles were adjusted for Scenario 1 similar to the Green Resource Future Scenario 1, the total PVRR costs would be less. (As noted above, the Goshen and Yakima topology adjustments relieve artificial transmission constraints that inflate portfolio costs in the absence of the Energy Gateway transmission additions.) Unless significant wind resources are added to Wyoming as in the high

CO_2 and high natural gas cost scenarios, the utilization percentage of Gateway West and Gateway South would be fairly minimal. This would be a prime factor for the Company to decide not to pursue building these incremental transmission segments.

Energy Gateway Treatment in the Integrated Resource Plan

The System Optimizer analysis and previous stochastic production cost modeling demonstrated the logical connection between several transmission scenarios and incremental resource requirements. The modeling analysis indicates that the full Energy Gateway strategy is cost-effective assuming incremental wind additions are in line with the Company's current wind acquisition plans. However, without the mandate for additional renewable resources and regulatory support for associated transmission investments, further evaluation of proposed incremental transmission originating in Wyoming (most economic location for wind) would be required to determine need for Company load service. One thing is clear; the Energy Gateway strategy provides the necessary capacity for the Company to be aligned with a green resource future.

What is also important to note is that the cost range for the scenarios considered is relatively close, which suggests economics do not drive a clear selection. The key decision is what is the best investment based on an assumed future state.

Assuming a future scenario with reduced renewable energy requirements or other energy sources such as geothermal resources located in the west or implementation of new technologies presents a significant risk if the assumptions turn out wrong and transmission expansion was halted.

The Company currently believes that strong support for renewables development will continue (notwithstanding regulatory hurdles and government budgetary pressures that may erode financial support programs), and therefore concludes that proceeding with the full Gateway expansion scenario is the most prudent strategy given regulatory uncertainty, benefits from resource diversity, and the long lead time for adding new transmission facilities. Consequently, the Company decided to reflect the full Energy Gateway in portfolios used to develop its 2011 IRP preferred portfolio. Further, the Company seeks acknowledgment of Energy Gateway plans as outlined in the transmission expansion action plan (Chapter 10).

CHAPTER 5 – RESOURCE NEEDS ASSESSMENT

Chapter Highlights

- *On both a capacity and energy basis, PacifiCorp calculates load and resource balances using existing resource levels, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability at the time of the coincident system peak load hour.*
- *For capacity expansion planning, the Company uses a 13-percent planning reserve margin applied to PacifiCorp's obligation (loads plus sales) less firm purchases and dispatchable load control capacity. The 13-percent planning reserve margin is supported by a stochastic loss of load study conducted in 2010 (See Appendix J).*
- *The system peak load is forecasted to grow at a compounded average annual growth rate of 2.1 percent for 2011 through 2020. The eastern system peak is expected to continue growing faster than its western system peak, at 2.4 percent and 1.4 percent, respectively. On an energy basis, PacifiCorp expects system-wide average load growth of 1.8 percent per year from 2011 through 2020.*
- *The Company projects a summer peak resource deficit of 326 MW for the PacifiCorp system beginning in 2011. The table below shows the system capacity position forecast, indicating the widening capacity deficit, which reaches 3,852 MW by 2020.*
- *The near-term deficit will be met by additional demand-side management programs, renewables, and market purchases. Beginning 2014, base load, intermediate load, or both types of resource additions will be necessary to cover the capacity deficit.*

	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)

Introduction

This chapter presents PacifiCorp's assessment of resource need, focusing on the first ten years of the IRP's 20-year study period, 2011 through 2020. The Company's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are addressed in detail in Appendix A. The summary level coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are comprised of a year-by-year comparison of projected loads against the resource base without new additions. This comparison indicates when PacifiCorp is expected to be either deficit or surplus on both a capacity and energy basis for each year of the planning horizon.

Coincident Peak Load Forecast

The 2011 IRP used the Company's October 2010 forecast, which also supported development of the ten year business plan. Table 5.1 shows the annual coincident peak megawatts for the East and West-side of the system as reported in the capacity load and resource balance, prior to any load reductions from energy efficiency (Class 2 DSM). The system peak load grows at a compounded average annual growth rate (CAAGR) of 2.1 percent for 2011 through 2020.

Table 5.1 – Forecasted Coincidental Peak Load in Megawatts, Prior to Energy Efficiency Reductions

Region	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
East	7,184	7,344	7,566	7,805	8,009	8,201	8,377	8,544	8,712	8,896
West	3,266	3,374	3,395	3,448	3,491	3,541	3,584	3,650	3,666	3,713
System	**10,450**	**10,718**	**10,961**	**11,253**	**11,500**	**11,742**	**11,961**	**12,194**	**12,378**	**12,609**

PacifiCorp's eastern system peak is expected to continue growing faster than the western system peak, with average annual growth rates of 2.4 percent and 1.4 percent, respectively, over the forecast horizon. The main drivers for the higher coincident peak load growth for the eastern states include the following:

- Customer growth in residential and commercial classes.
- New large commercial customers such as data centers.
- Increased usage by Industrial class due to addition of new large industrial customers or expansion by existing customers.

Existing Resources

For the forecasted 2011 summer peak, PacifiCorp owns, or has interest in, resources with an expected system peak capacity of 12,459 MW. Table 5.2 provides anticipated system peak capacity ratings by resource category as reflected in the IRP load and resource balance for 2011. Note that capacity ratings in the following tables are rounded to the nearest megawatt.

Table 5.2 – Capacity Ratings of Existing Resources

Resource Type [1/]	MW [2/]	Percent (%)
Pulverized Coal	6,188	49.7
Gas-CCCT	2,025	16.3
Gas-SCCT	358	2.9
Hydroelectric	1,236	9.9
Class 1 DSM [3/]	324	2.6
Renewables	297	2.4

Resource Type [1/]	MW [2/]	Percent (%)
Purchase [4/]	1,510	12.1
Qualifying Facilities	239	1.9
Interruptible	281	2.3
Total	**12,459**	**100**

[1/] Sales and Non-Owned Reserves are not included.
[2/] Represents the capacity available at the time of system peak used for preparation of the capacity load and resource balance. For specific definitions by resource type see the section entitled, "Load and Resource Balance Components", later in this chapter.
[3/] Class 1 DSM is PacifiCorp's dispatchable load control.
[4/] Purchases constitute contracts that do not fall into other categories such as hydroelectric, renewables, and natural gas.

Thermal Plants

Table 5.3 lists existing PacifiCorp's coal fired thermal plants and Table 5.4 lists existing natural gas fired plants. As a modeling assumption, no coal or gas plants are shut down during the IRP 20-year planning period. Plant operating decisions will be based on an assessment of plant economics that considers the cost for replacement power given environmental compliance requirements, market conditions, and other factors.

Table 5.3 – Coal Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Load and Resource Balance Capacity (MW)
Carbon 1	100	Utah	67
Carbon 2	100	Utah	105
Cholla 4	100	Arizona	387
Colstrip 3	10	Montana	74
Colstrip 4	10	Montana	74
Craig 1	19	Colorado	84
Craig 2	19	Colorado	83
Dave Johnston 1	100	Wyoming	105
Dave Johnston 2	100	Wyoming	105
Dave Johnston 3	100	Wyoming	220
Dave Johnston 4	100	Wyoming	330
Hayden 1	24	Colorado	45
Hayden 2	13	Colorado	33
Hunter 1	94	Utah	419
Hunter 2	60	Utah	269
Hunter 3	100	Utah	460
Huntington 1	100	Utah	463
Huntington 2	100	Utah	450
Jim Bridger 1	67	Wyoming	357
Jim Bridger 2	67	Wyoming	351

Plant	PacifiCorp Percentage Share (%)	State	Load and Resource Balance Capacity (MW)
Jim Bridger 3	67	Wyoming	353
Jim Bridger 4	67	Wyoming	353
Naughton 1	100	Wyoming	160
Naughton 2	100	Wyoming	210
Naughton 3	100	Wyoming	330
Wyodak	80	Wyoming	271
TOTAL – Coal			**6,173**

Table 5.4 – Natural Gas Plants

Natural Gas -fueled	PacifiCorp Percentage Share (%)	State	Load and Resource Balance Capacity (MW)
Chehalis	100	Washington	509
Currant Creek	100	Utah	506
Gadsby 1	100	Utah	57
Gadsby 2	100	Utah	69
Gadsby 3	100	Utah	100
Gadsby 4	100	Utah	41
Gadsby 5	100	Utah	39
Gadsby 6	100	Utah	39
Hermiston 1 *	50	Oregon	233
Hermiston 2 *	50	Oregon	233
Lake Side	100	Utah	545
Little Mountain	100	Utah	12
James River Cogen (CHP)	100	Washington	14
TOTAL – Gas and Combined Heat & Power			**2,397**

* Remainder of Hermiston plant is purchased under contract by the Company for a plant total of 932 MW.

Renewables

PacifiCorp's renewable resources, presented by resource type, are described below.

Wind

PacifiCorp acquires wind power from owned plants and various purchase agreements. Since the 2008 IRP Update, PacifiCorp has acquired several large wind resources including McFadden Ridge I at 28.5 MW and Dunlap I at 111 MW. These projects came on line in 2009 and 2010, respectively. The Company also entered into 20-year power purchase agreements for the total output of several projects that include Top of the World at 200.2 MW, and four other projects due online in 2011 and 2012 that include Power County Wind Park North and South for a total of 43.6 MW, and Pioneer Wind I and II at a total of 99 MW.

Table 5.5 shows existing wind facilities owned by PacifiCorp, while Table 5.6 shows existing wind power purchase agreements.

Table 5.5 – PacifiCorp-owned Wind Resources

Utility-Owned Wind Projects	Capacity (MW)	L&R Capacity Contribution (MW)	In-Service Year	State
Foote Creek I *	33	6	2005	WY
Leaning Juniper	101	37	2006	OR
Goodnoe Hills East Wind	94	23	2007	WA
Marengo	140	6	2007	WA
Glenrock Wind I	99	11	2008	WY
Glenrock Wind III	39	2	2008	WY
Marengo II	70	4	2008	WA
Rolling Hills Wind	99	5	2008	WY
Seven Mile Hill Wind	99	12	2008	WY
Seven Mile Hill Wind II	20	0	2008	WY
High Plains	99	9	2009	WY
McFadden Ridge 1 **	29	2	2009	WY
Dunlap 1 **	111	6	2010	WY
TOTAL – Owned Wind	**1,032**	**124**		

*Net total capacity for Foote Creek I is 41 MW.
**New since the 2008 IRP Update.

Table 5.6 – Wind Power Purchase Agreements and Exchanges

Power Purchase Agreements / Exchanges	Capacity (MW)	L&R Capacity Contribution (MW)	In-Service Year	State
Foote Creek II	2	0	2005	WY
Foote Creek III	25	3	2005	WY
Foote Creek IV	17	2	2005	WY
Combine Hills	41	1	2003	OR
Stateline Wind	210	6	2002	OR / WA
Wolverine Creek	65	11	2005	ID
Rock River I	50	7	2006	WY
Mountain Wind Power I	60	26	2008	WY
Mountain Wind Power II	80	31	2008	WY
Spanish Fork	19	6	2008	UT
Three Buttes Wind Power (Duke)	99	0	2009	WY
Three Mile Canyon Wind	10	0	2009	OR
Oregon Wind Farm I	45	13	2009	OR
Oregon Wind Farm II	20	1	2010	OR
Casper Wind	17	1	2010	WY
Top of the World *	200	5	2010	WY
Pioneer Wind I **	50	9	2011	WY
Pioneer Wind II **	50	9	2012	WY
Power County Wind Park North **	22	8	2011	ID
Power County Wind Park South **	22	7	2011	ID
TOTAL – Purchased Wind	**1,101**	**167**		

*New since the 2008 IRP Update.
**New plants under construction with newly signed power purchase agreements.

PacifiCorp also has wind integration, storage and return agreements with Bonneville Power Administration (BPA), Eugene Water and Electric Board, Public Service Company of Colorado, and Seattle City Light.

Geothermal

PacifiCorp owns and operates the Blundell Geothermal Plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus and is rated at 0.28 MW.

Biomass / Biogas

Since the 2008 IRP Update, PacifiCorp has added less than 1 MW of resources. These types of resources are primarily QF.

Renewables Net Metering

As of year-end 2010, PacifiCorp had 2,419 net metering customers throughout its six-state territory, generating more than 10,000 kW using solar, hydro, wind, and fuel cell technologies. About 92 percent of customer generators are solar-based, followed by wind-based generation at 7 percent of total generation.

Net metering has grown by more than 50 percent from last year. The Company averaged 68 new net metered customers a month in 2010, compared to 39 new customers per month in 2009.

Hydroelectric Generation

PacifiCorp owns 1,236 MW of hydroelectric generation capacity and purchases the output from 346 MW of other hydroelectric resources. These resources account for approximately 10 percent of PacifiCorp's total generating capability, in addition to providing operational benefits such as flexible generation, spinning reserves and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate or purchase from hydroelectric plants is dependent upon a number of factors, including the water content of snow pack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. When these conditions result in above average runoff, PacifiCorp is able to generate a higher than average amount of electricity using its hydroelectric plants. However, when these factors are unfavorable, PacifiCorp must rely to a greater degree on its more expensive thermal plants and the purchase of electricity to meet the demands of its customers.

Hydroelectric purchases are categorized into three groups as shown in Table 5.7, which reports 2011 capacity included in the load and resource balance.

Table 5.7 – Hydroelectric Contracts

Hydroelectric Contracts by Load and Resource Balance Category	2011 Capacity (MW)
Hydroelectric	254
Purchases – Hydroelectric	63
Qualifying Facilities - Hydroelectric	29
Total Contracted Hydroelectric Resources	**346**

Table 5.8 provides an operational profile for each of PacifiCorp's owned hydroelectric generation facilities. The dates listed refer to a calendar year.

Table 5.8 – PacifiCorp Owned Hydroelectric Generation Facilities - Load and Resource Balance Capacities

Plant	State	Load and Resource Balance Capacity (MW)
West		
Big Fork	Montana	3
Clearwater 1	Oregon	12
Clearwater 2	Oregon	21
Copco 1 and 2	California	55
Fish Creek	Oregon	12
Iron Gate	California	19
JC Boyle	Oregon	82
Lemolo 1	Oregon	31
Lemolo 2	Oregon	30
Merwin	Washington	26
Rogue	Oregon	34
Small West Hydro [1/]	California / Oregon / Washington	3
Soda Springs	Oregon	12
Swift 1	Washington	255
Swift 2 [2/]	Washington	64
Toketee and Slide	Oregon	60
East-Side / West-Side	Oregon	3
Yale	Washington	150
East		
Bear River	Idaho / Utah	92
Small East Hydro [3/]	Idaho / Utah / Wyoming	19
TOTAL – Hydroelectric before contracts		**983**
Hydroelectric Contracts		**254**
TOTAL – Hydroelectric		**1,236**

[1/] Includes Bend, Condit, Fall Creek, and Wallowa Falls

[2/] Cowlitz County PUD owns Swift No. 2, and is operated in coordination with the other projects by PacifiCorp.

[3/] Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Snake Creek, Olmstead, Fountain Green, Veyo, Sand Cove, Viva Naughton, and Gunlock.

Hydroelectric Relicensing Impacts on Generation

Table 5.9 lists the estimated impacts to average annual hydro generation from FERC license renewals. PacifiCorp assumed that all hydroelectric facilities currently involved in the relicensing process will receive new operating licenses, but that additional operating restrictions imposed in new licenses, such as higher bypass flow requirements, will reduce generation available from these facilities.

Table 5.9 – Estimated Impact of FERC License Renewals on Hydroelectric Generation

Year	Lost Generation (MWh)
2011	167,112
2012	201,228
2013	201,228
2014	201,228
2015	201,228
2016	201,228
2017	201,228
2018	201,228
2019	201,228
2020	918,048
2021	918,048
2022	918,048
2023	918,048
2024	918,048
2025	918,048
2026	918,048
2027	918,048
2028	918,048
2029	918,048
2030	918,048

Demand-side Management

DSM resources/products vary in their dispatchability, reliability of results, term of load reduction benefit and persistence over time. Each has its value and place in effectively managing utility investments, resource costs and system operations. Those that have greater persistence and firmness can be reasonably relied upon as a base resource for planning purposes; those that do not are more suited as system reliability resource options. Reliability tools are used to avoid outages or high resource costs as a result of weather conditions, plant outages, market prices, and unanticipated system failures. DSM resources/products can be divided into four general classes based on their relative characteristics, the classes are:

- **Class 1 DSM: Resources from fully dispatchable or scheduled firm capacity product offerings/programs** – Class 1 DSM programs are those for which capacity savings occur as a result of active Company control or advanced scheduling. Once customers agree to participate in Class 1 DSM program, the timing and persistence of the load reduction is involuntary on their part within the agreed limits and parameters of the program. In most cases, loads are shifted rather than avoided. Examples include residential and commercial central air conditioner load control programs ("Cool Keeper") that are dispatchable in nature and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program).

- **Class 2 DSM: Resources from non-dispatchable, firm energy and capacity product offerings/programs** – Class 2 DSM programs are those for which sustainable energy and related capacity savings are achieved through facilitation of technological advancements in equipment, appliances, lighting and structures. Class 2 DSM programs generally provide financial and/or service incentives to customers to replace equipment and appliances in existing customer owned facilities (or to upgrade in new construction) to more efficient lighting, motors, air conditioners, insulation levels, windows, etc. The savings endure over the life of the improvement (are considered firm). Program examples include air conditioning efficiency programs ("Cool Cash"), comprehensive commercial and industrial new and retrofit energy efficiency programs ("Energy FinAnswer" and "FinAnswer Express"), refrigerator recycling programs ("See ya later, refrigerator®") and comprehensive home improvement retrofit programs ("Home Energy Saving").

- **Class 3 DSM: Resources from price responsive energy and capacity product offerings/programs** – Class 3 DSM programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. Savings are measured at a customer-by-customer level (via metering and/or metering data analysis against baselines), and customers are compensated or charged in accordance with a program's pricing parameters. As a result of their voluntary nature, savings are less predictable, making them less suitable to incorporate into resource planning exercises, at least until such time that their size and customer behavior profile provide sufficient information for a reliable diversity result for modeling and planning purposes. Savings typically only endure for the duration of the incentive offering and loads tend to be shifted rather than avoided. Program examples include large customer energy bid programs ("Energy Exchange"), time-of-use pricing plans, critical peak pricing plans, and inverted tariff designs.

- **Class 4 DSM: Resources from energy efficiency education and non-incentive based voluntary curtailment programs/communications/pleas** – Class 4 DSM programs resources may be in the form of energy and/or capacity reductions. The reductions are typically achieved from voluntary actions taken by customers, behavior changes, to save energy and/or reduce costs, benefit the environment or in response to public or Company pleas to conserve or shift their usage to off peak hours. Program savings are difficult to measure and in many cases tend to vary over time. While not specifically relied upon in resource planning, Class 4 DSM savings appear in historical load data therefore into resource planning through the plan load forecasts. The value of Class 4 DSM is long-term in nature. Class 4 DSM programs help foster an understanding and appreciation as to why utilities seek customer participation in Classes 1, 2 and 3 DSM programs, as well provide a foundational understanding of how to use energy wisely. Program examples include Utah's PowerForward program, Company brochures with energy savings tips, customer newsletters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs such as "Let's turn the answers on" and "***watt***smart" campaigns. Studies have shown potential savings from behavior changes, especially when coupled with complimentary DSM programs to assist customers with a portion of the actions taken.[33] Although these behavior savings are often difficult and costly to track and measure, enough studies have measured their effects to expect at least a degree of savings (equal to or greater than those expected to be acquired through DSM programs; e.g. 1 plus percent) to be realized and reflected in customer usage and future load forecasts.

PacifiCorp has been operating successful DSM programs since the late 1970s. While the Company's DSM focus has remained strong over this time, since the 2001 western energy crisis, the Company's DSM pursuits have been expanded in terms of investment level, state presence, breadth of DSM resources pursued (Classes 1 through 4) and resource planning considerations. Company investments continue to increase year on year with 2010 investments exceeding $112 million (all states). Work continues on the expansion of program portfolios in all states. In 2010 Wyoming's results more than doubled those of 2009, the first year programs were widely available across all customer sectors. In Oregon the Company continues to work closely with the ETO on helping to identify additional resource opportunities, improve delivery and communication coordination, and ensure adequate funding and Company support in pursuit of DSM resource targets. The Company is also actively pursuing Class 1 DSM load management opportunities in response to the growing need for capacity resources in the west.

The following represents a brief summary of the existing resources by class.

Class 1 Demand-side Management

Currently there are four Class 1 DSM programs running across PacifiCorp's six state service area; Utah's "Cool Keeper" residential and small commercial air conditioner load control program; Idaho's and Utah's scheduled firm irrigation load management programs; and Idaho's and Utah's dispatchable irrigation load management programs. In 2010 these programs accounted for over 519 MW of participating Class 1 DSM program resources under management helping the Company better manage peak load requirement periods.

Class 2 Demand-side Management

The Company currently manages ten distinct Class 2 DSM products, many of the products are offered in multiple states. In all, the combination of Class 2 DSM programs across the five states where the Company is directly responsible for delivery totals thirty. The cumulative historical energy and capacity savings (1992-2010) associated with Class 2 DSM program activity has accounted for nearly 4.4 million MWh and approximately 800 MW of capacity reductions.

Class 3 Demand-side Management

The Company has numerous Class 3 DSM programs currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), residential seasonal inverted rates (Utah and Wyoming), residential year-around inverted rates (California, Oregon, and Washington) and Energy Exchange programs (Oregon, Utah, Idaho, Wyoming and Washington). Savings associated with these programs are captured within the Company's load forecast, with the exception of the more immediate call-to-action programs like

[33] John Green and Lisa A. Skumatz, "Evaluating the Impacts of Education/Outreach Programs: Lessons on Impacts, Methods and Optimal Education, "paper presented at the American Council for an Energy Efficient Economy summer Study on Energy Efficiency in Buildings (2000).

Energy Exchange and Utah's PowerForward programs. The impacts of these programs are thus captured in the integrated resource planning framework. Energy Exchange and Utah's PowerForward are examples of Class 3 DSM programs relied upon as reliability resources as opposed to base resources. System-wide participation in metered time-of-day and time-of-use programs as of December 31, 2010 was approximately 19,700 customers. All of the Company's residential customer base on default non-time of use rates are currently subject to inverted rate plans either seasonally or year-around.

PacifiCorp continues to evaluate Class 3 DSM programs for applicability to long-term resource planning. As discussed in Chapter 6, five Class 3 DSM programs were provided as resource options in preliminary IRP modeling scenarios.

Class 4 Demand-side Management

Educating customers regarding energy efficiency and load management opportunities is an important component of the Company's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts, bill messages, newsletters, school education programs, and personal contact. Specific firm load reductions due to Class 4 DSM activity will show up in Class 2 DSM program results and non-program/documented reductions in the load forecast over time.

Table 5.10 summarizes the existing DSM programs. Note that since Class 2 DSM is determined as an outcome of resource portfolio modeling, and is included in the preferred portfolio, existing Class 2 DSM is reported as having zero MW.

Table 5.10 – Existing DSM Summary, 2011-2020

Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2011-2020 Period?
1	Residential/small commercial air conditioner load control	123 MW summer peak	Yes
	Irrigation load management	201 MW summer peak	Yes
	Interruptible contracts	232 MW	Yes. Additional Monsanto buy-through capacity of 49 MW is included for the capacity load and resource balance, for a total of 281 MW.
2	Company and ETO programs	0 MW	No. Class 2 DSM programs are modeled as resource options in the portfolio development process, and included in the preferred portfolio.
3	Energy Exchange	0-37 MW (assumes no other Class 3 DSM competing products running)	No. Program is leveraged as economic and reliability resource dependent on market prices/system loads.
	Time-based pricing	MWa/MW unavailable 20,000 customers	No. Historical behavior is captured in load forecast.

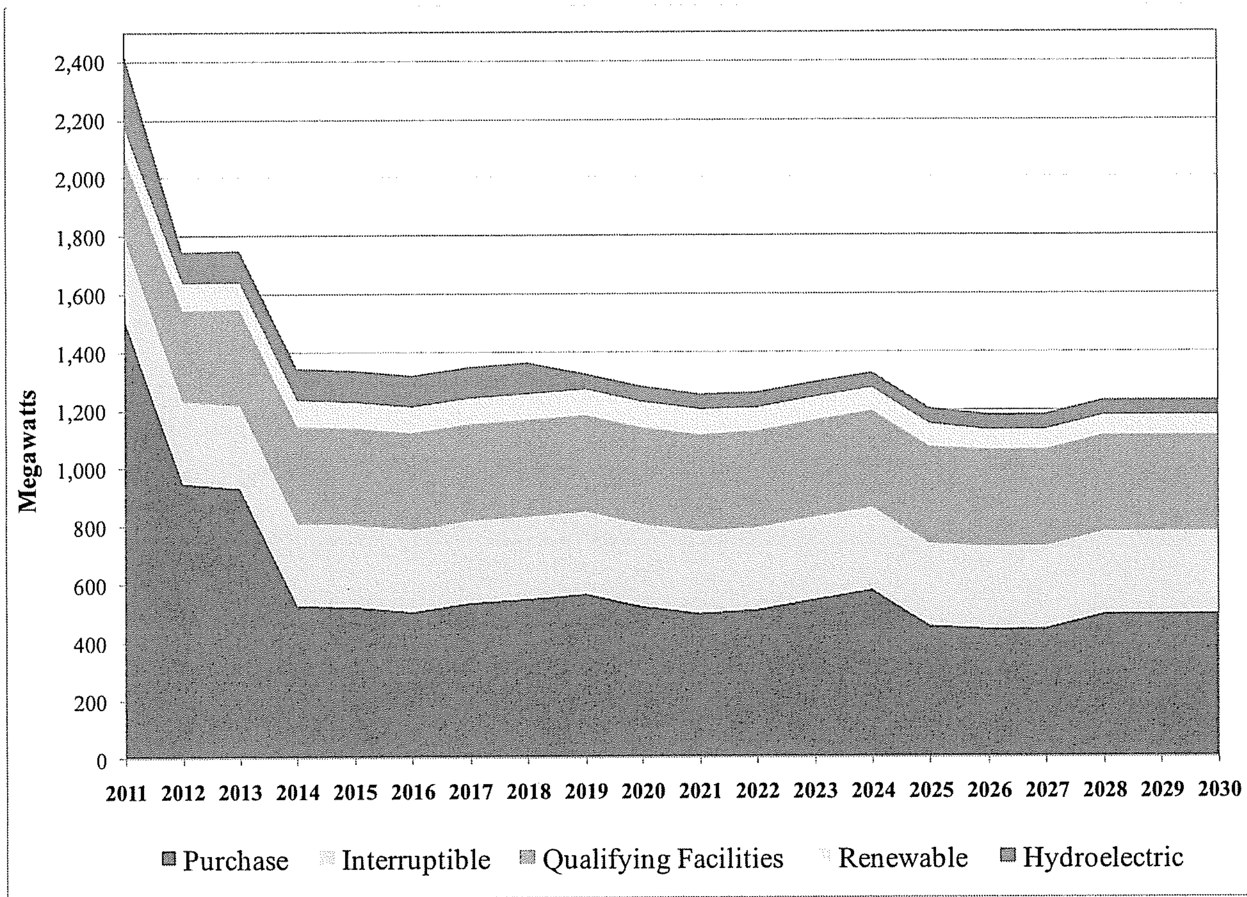
Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2011-2020 Period?
	Inverted rate pricing	MWa/MW unavailable 1.47 million residential customers	No. Historical behavior is captured in load forecast.
4	PowerForward	0-80 MW summer peak	No. Program is leveraged as economic and reliability resource dependent on market prices/system loads.
	Energy Education	MWa/MW unavailable	No. Program is captured in load forecast over time and other Classes 1 and 2 DSM program results.

Power Purchase Contracts

PacifiCorp obtains the remainder of its energy requirements, including any changes from expectations, through long-term firm contracts, short-term firm contracts, and spot market purchases.

Figure 5.1 presents the contract capacity in place for 2011 through 2020 as of November 2010. As shown, major capacity reductions in purchases and hydro contracts occur. (For planning purposes, PacifiCorp assumes that current qualifying facility and interruptible load contracts are extended through the end of the IRP study period.) Note that renewable wind contracts are shown at their capacity contribution levels.

Figure 5.1 – Contract Capacity in the 2011 Load and Resource Balance

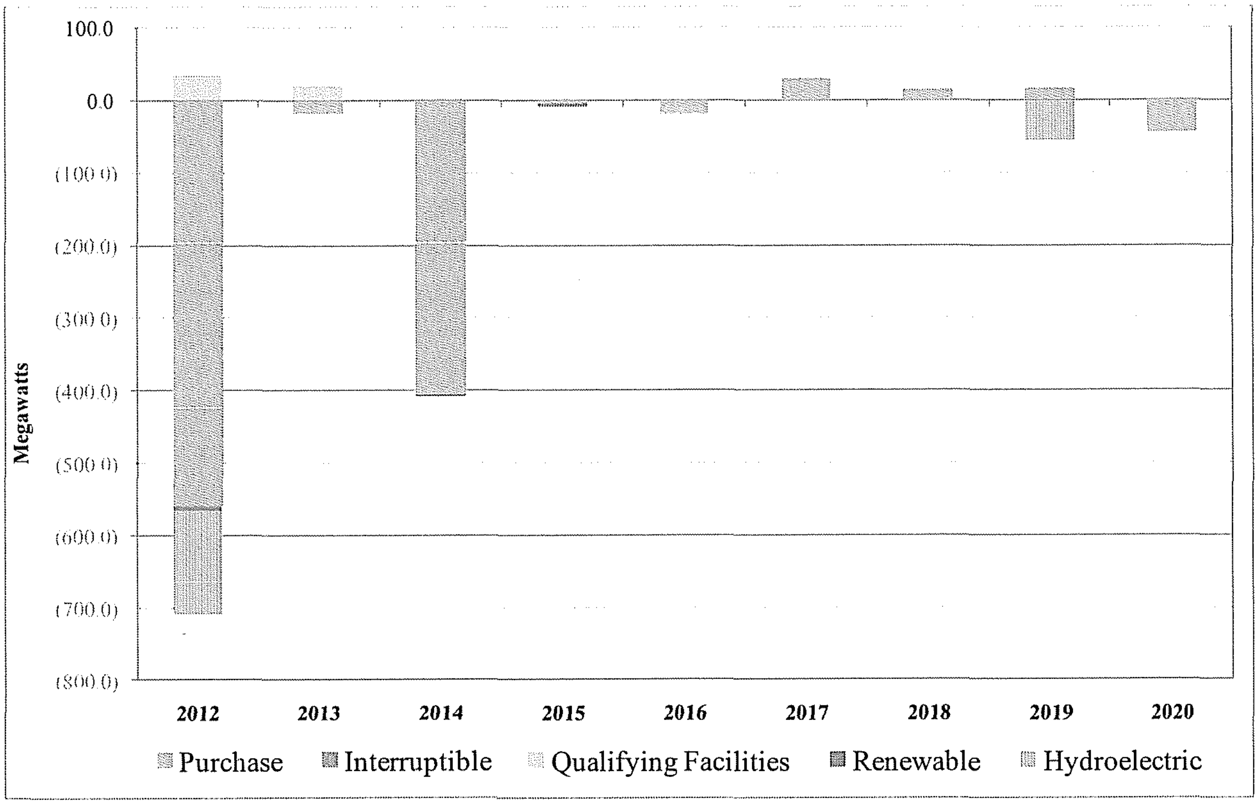


Listed below are the major contract expirations expiring between the summer 2011 and summer 2012:

- BPA Peaking – 575 MW
- Morgan Stanley – 100 MW
- Morgan Stanley – 100 MW
- Colockum Capacity Exchange – 108MW
- Rocky Reach – 65 MW
- Grant Displacement – 63 MW

Figure 5.2 shows the year-to-year changes in contract capacity. Early year fluctuations are due to changes in short-term balancing contracts of one year or less, and expiration of the contracts cited above.

Figure 5.2 – Changes in Power Contract Capacity in the Load and Resource Balance



Load and Resource Balance

Capacity and Energy Balance Overview

The purpose of the load and resource balance is to compare the annual obligations for the first ten years of the study period with the annual capability of PacifiCorp's existing resources, absent new resource additions. This is done with respect to two views of the system, the capacity balance and energy balance.

The capacity balance compares generating capability to expected peak load at time of system peak load hours. It is a key part of the load and resource balance because it provides guidance as to the timing and severity of future resource deficits. It was developed by first determining the system coincident peak load hour for each of the first ten years (2011-2020) of the planning horizon. The peak load and the firm sales were added together for each of the annual system peak hours to compute the annual peak-hour obligation. Then the annual firm-capacity availability of the existing resources was determined for each of these annual system peak hours. The annual resource deficit (surplus) was then computed by multiplying the obligation by the planning reserve margin (PRM), and then subtracting the result from the existing resources.

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy over the first ten years of the planning horizon (2011-2020). The average obligation (load plus sales) was computed and subtracted from the average existing resource availability for each month and time-of-day period. This was done for each side of the PacifiCorp system as well as at the system level. The energy balance complements the capacity balance in that it also indicates when resource deficits occur, but it also provides insight into what type of resource will best fill the need. The usefulness of the energy balance is limited as it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed with the portfolio studies described in Chapter 8.

Load and Resource Balance Components

The capacity and energy balances make use of the same load and resource components in their calculation. The main component categories consist of the following: existing resources, obligation, reserves, position, and reserve margin. This section provides a description of these various components.

Existing Resources
A description of each of the resource categories follows:

- **Thermal**. This category includes all thermal plants that are wholly-owned or partially-owned by PacifiCorp. The capacity balance counts them at maximum dependable capability at time of system peak. The energy balance also counts them at maximum dependable capability, but de-rates them for forced outages and maintenance. This includes the existing fleet of 11 coal-fired plants, six natural gas-fired plants, and one cogeneration unit. These thermal resources account for roughly two-thirds of the firm capacity available in the PacifiCorp system.

- **Hydro**. This category includes all hydroelectric generation resources operated in the PacifiCorp system as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources by the maximum capability that is sustainable for one hour at the time of system peak, an approach consistent with current WECC capacity reporting practices. The energy associated with critical level stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. The energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation, are also accounted for. Over 90 percent of the hydroelectric capacity is situated on the west side of the PacifiCorp system.

  The Public Service Commission of Utah, in its 2008 IRP acknowledgment order, directed the Company to continue investigating the hydro capacity accounting methodology currently under consideration for regional resource adequacy reporting purposes in the Pacific Northwest. This accounting methodology extends the one-hour sustained peaking period to an 18-hour sustained peaking period: the six highest load hours over three consecutive days of highest demand. Appendix K provides PacifiCorp's assessment of the applicability and impact of moving to the 18-hour standard.

- **Dispatchable Load Control (Class 1 DSM).** In 2011, there are projected to be approximately 324 MW of Class 1 DSM programs included as existing resources. These are projected to increase to 329 MW by 2012. Both the capacity balance and the energy balance count DSM programs by program capacity available for system dispatch. Dispatchable load control resources directly curtail load and thus planning reserves are not held for them.[34]

- **Renewable.** This category contains one geothermal project, 21 existing wind projects and two planned wind projects. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. Project-specific capacity credits for the wind resources were statistically determined using a peak load carrying capability (PLCC) methodology.[35] Wind energy is counted according to hourly generation data used to model the projects.

- **Purchase.** This includes all of the major contracts for purchases of firm capacity and energy in the PacifiCorp system. The capacity balance counts these by the maximum contract availability at time of system peak. The energy balance counts the optimum model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

- **Qualifying Facilities (QF).** All QF that provide capacity and energy are included in this category. Like other power purchases, the capacity balance counts them at maximum system peak availability and the energy balance counts them by optimum model dispatch. It is assumed that all QF agreements will stay in place for the entire duration of the 20-year planning period. It should be noted that three of the QF resources (Kennecott, Tesoro, and US Magnesium) are considered non-firm and thus do not contribute to capacity planning.

- **Interruptible.** There are three east-side load curtailment contracts in this category. These agreements with Monsanto, MagCorp and Nucor provide 281 MW of load interruption capability at time of system peak. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus planning reserves are not held for them.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load and firm contracted sales of energy and capacity. The following are descriptions of each of these components:

- **Load**. The largest component of the obligation is the retail load. The capacity balance counts the peak load (MW) at the hour of system coincident peak load. The system coincident peak hour is determined by summing the loads for all locations (topology bubbles with loads). Loads reported by East and West control areas thus reflect loads at the time of PacifiCorp's

[34] Energy efficiency measures—Class 2 DSM programs—are treated as future resources that reduce forecasted loads (see Appendix A). Consequently, they are not included as existing resources in the capacity load and resource balance.

[35] See, Dragoon, K., Dvortsov, V, "Z-method for power system resource adequacy applications" IEEE Transactions on Power Systems (Volume 21, Issue 2, May 2006), pp. 982 – 988.

coincident system peak. The energy balance counts the load as an average of monthly as well as annual time-of-day energy (MWa).

- **Sales**. This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system peak and the energy balance counts them by optimum model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view.

Reserves
The reserves are the total megawatts of planning and non-owned reserves that must be held for this load and resource balance. A description of the two types of reserves follows:

- **Planning reserves**. This is the total reserves that must be held to provide the planning reserve margin (PRM). The planning reserve margin accounts for WECC operating reserves[36], load forecast errors, and other long-term resource adequacy planning uncertainties. The following equation expresses the planning reserve requirement.

  ***Planning reserves** = (Obligation – Firm Purchases – Class 1 DSM – Interruptible) x PRM*

- **Non-owned reserves**. There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. This amounts to an annual reserve obligation of about 7 MW and 70 MW on the west and east-sides, respectively. As the balancing authority, PacifiCorp is required to hold reserves for these counterparties but is not required to serve any associated loads.

Position
The position is the resource surplus (deficit) after subtracting obligation plus required reserves from the resource total. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

Reserve Margin
The reserve margin is the difference between system capability and anticipated peak demand, measured either in megawatts or as a percentage of the peak load. A positive reserve margin indicates that system capabilities exceed system obligations. Conversely, a negative reserve margin indicates that system capabilities do not meet obligations. If system capabilities equal obligations, then the reserve margin is zero. It should be pointed out that the position can be negative when the corresponding reserve margin is non-negative. This is because the reserve margin is measured relative only to obligation, while the position is measured relative to obligation plus reserves. PacifiCorp adopted a 13 percent target planning reserve margin for the 2011 IRP. Note that a resource can only serve load in another topology location if there is adequate transfer capacity. PacifiCorp captures transfer capacities as part of its capacity expansion planning process. The supporting loss of load probability study is included as Appendix J.

[36] As part of the WECC, PacifiCorp is currently required to maintain at least 5 percent and 7 percent operating reserve margins on hydro and thermal load-serving resources, respectively.

Capacity Balance Determination

Methodology

The capacity balance is developed by first determining the system coincident peak load hour for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system peak hours and summed as follows:

Existing Resources = *Thermal + Hydro + Class 1 DSM + Renewable + Firm Purchases + QF + Interruptible*

The peak load and firm sales are then added together for each of the annual system peak hours to compute the annual peak-hour obligation:

Obligation = *Load + Sales*

The amount of reserves to be added to the obligation is then calculated. This is accomplished by first removing the firm purchase and load curtailment components of the existing resources from the obligation. This resulting amount is then multiplied by the planning reserve margin. The non-owned reserves are then added to this result to yield the megawatts of required reserves. The formula for this calculation is the following:

Reserves = *(Obligation – Firm Purchases – Class 1 DSM – Interruptible) x PRM + Non-owned reserves*

Finally, the annual capacity position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources as shown in the following formula:

Capacity Position = *Existing Resources – Obligation – Reserves*

Firm capacity transfers from PacifiCorp's west to east control areas are reported for the east capacity balance, while capacity transfers from the east to west control areas are reported for the west capacity balance. Capacity transfers represent the optimized control area interchange at the time of the system coincident peak load as determined by the System Optimizer model.[37]

Load and Resource Balance Assumptions

The assumptions underlying the current load and resource balance are generally the same as those from the 2008 IRP update with a few exceptions. The following is a summary of these assumption changes:

- **Wind Commitment.** In October 2010, the Company's commitment to acquire 1,400 MW of renewable resources was met with recent wind projects:

[37] West-to-east and east-to-west transfers should be identical. However, decimal precision of a transmission loss parameter internal to the System Optimizer model results in a slight discrepancy (less than 2 MW) between reported values.

- Dunlap 1 – 111 MW
- Top of the World purchase – 200.2 MW

Additionally, the Company acquired other renewable projects since the last IRP, which include

- McFadden Ridge 1 – 28.5 MW
- Three Buttes Wind – 99 MW
- Casper Wind – 16.5 MW
- Four Mile Canyon Wind – 10 MW
- Four Corners Wind – 10 MW

New Qualifying Facility Wind Plants under construction

- Power County Wind Park North – 21.8 MW
- Power County Wind South – 21.8 MW
- Pioneer Wind I – 49.5 MW
- Pioneer Wind II – 49.5 MW

- **Coal plant turbine upgrades.** The current load and resource balance assumes 65 MW of coal plant turbine upgrades, which is down from the 134 MW assumed in the 2008 IRP Update Report. The reduction is due to capital reprioritization and issues with Sub-Synchronous Resonance (SSR) at the Jim Bridger plants.

Capacity Balance Results

Table 5.11 shows the annual capacity balances and component line items using a target planning reserve margin of 13 percent to calculate the planning reserve amount. Balances for the system as well as PacifiCorp's east and west control areas are shown. (It should be emphasized that while west and east balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis.) Also note that the new QF wind projects listed above are reported under the Qualifying Facilities line item rather than the Renewables line item.

Figures 5.3 through 5.5 display the annual capacity positions (resource surplus or deficits) for the system, west control area, and east control area, respectively. The large decrease in 2012 is primarily due to the expiration of the BPA peaking contract in August 2011.

Table 5.11 – System Capacity Loads and Resources Without Resource Additions

Calendar Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
East										
Thermal	6,019	6,026	6,028	6,028	6,028	6,046	6,046	6,046	6,046	6,046
Hydroelectric	133	133	133	133	133	129	129	129	129	129
Class 1 DSM	324	329	329	329	329	329	329	329	329	329
Renewable	179	179	179	178	176	176	176	176	176	176
Purchase	655	705	604	304	304	283	283	283	283	283
Qualifying Facilities	152	187	206	206	207	206	207	207	206	206
Interruptible	281	281	281	281	281	281	281	281	281	281
Transfers	810	451	414	456	311	499	547	299	361	328
East Existing Resources	8,553	8,290	8,174	7,916	7,768	7,949	7,997	7,749	7,811	7,778
Load	7,184	7,344	7,566	7,805	8,009	8,201	8,377	8,544	8,712	8,896
Sale	758	997	1,045	745	745	745	659	659	659	659
East Obligation	7,942	8,341	8,611	8,550	8,754	8,946	9,036	9,203	9,371	9,555
Planning reserves	869	913	962	993	1,019	1,047	1,059	1,080	1,102	1,126
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	939	984	1,032	1,063	1,090	1,117	1,129	1,151	1,173	1,196
East Obligation + Reserves	8,881	9,324	9,643	9,613	9,844	10,063	10,165	10,354	10,544	10,752
East Position	(328)	(1,034)	(1,469)	(1,698)	(2,076)	(2,114)	(2,168)	(2,605)	(2,732)	(2,974)
East Reserve Margin	9%	1%	(4%)	(7%)	(11%)	(11%)	(11%)	(15%)	(16%)	(18%)
West										
Thermal	2,552	2,552	2,556	2,556	2,556	2,556	2,541	2,550	2,550	2,550
Hydroelectric	1,103	958	958	957	958	959	958	958	902	745
Class 1 DSM	-	-	-	-	-	-	-	-	-	-
Renewable	77	71	71	71	71	71	71	71	71	71
Purchase	856	247	331	226	221	225	255	269	285	242
Qualifying Facilities	136	136	136	136	136	136	136	136	136	136
Transfers	(809)	(452)	(416)	(457)	(311)	(499)	(547)	(300)	(360)	(330)
West Existing Resources	3,915	3,512	3,636	3,489	3,631	3,447	3,415	3,684	3,584	3,414
Load	3,266	3,374	3,395	3,448	3,491	3,541	3,584	3,650	3,666	3,713
Sale	290	258	258	258	158	108	108	108	108	108
West Obligation	3,556	3,632	3,653	3,706	3,649	3,649	3,692	3,758	3,774	3,821
Planning reserves	351	440	432	452	446	445	447	454	454	465
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	357	447	438	459	452	452	453	460	460	472
West Obligation + Reserves	3,913	4,079	4,092	4,165	4,101	4,100	4,145	4,218	4,234	4,293
West Position	2	(567)	(456)	(676)	(470)	(653)	(730)	(534)	(650)	(879)
West Reserve Margin	13%	(3%)	1%	(5%)	0%	(5%)	(7%)	(1%)	(4%)	(10%)
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	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)
Reserve Margin	10%	(0%)	(3%)	(6%)	(8%)	(9%)	(10%)	(11%)	(13%)	(16%)

Figure 5.3 – System Capacity Position Trend

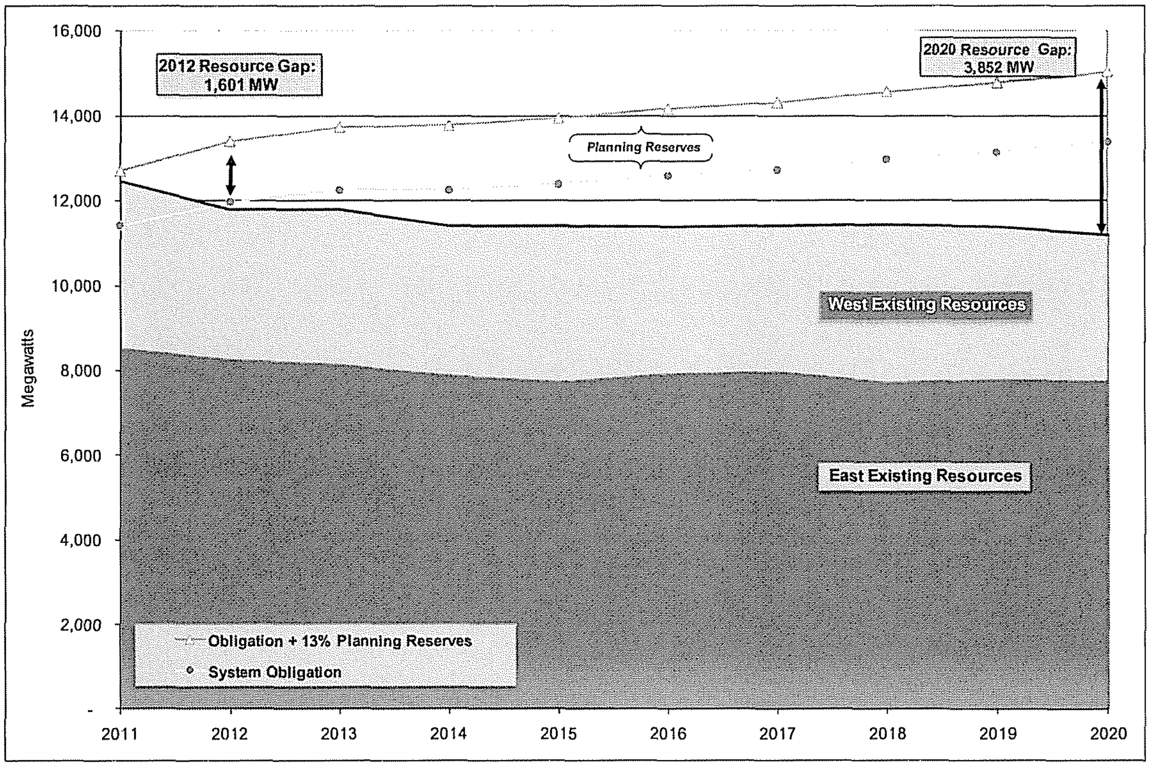


Figure 5.4 – West Capacity Position Trend

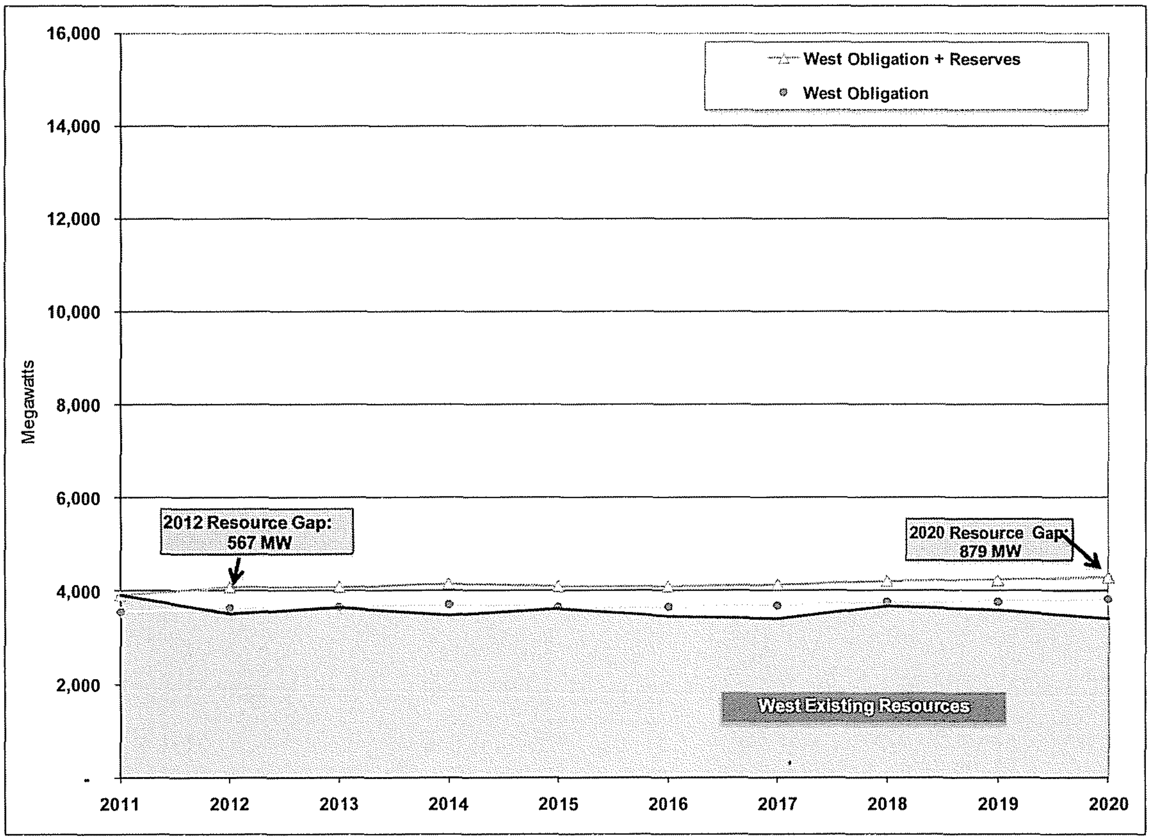
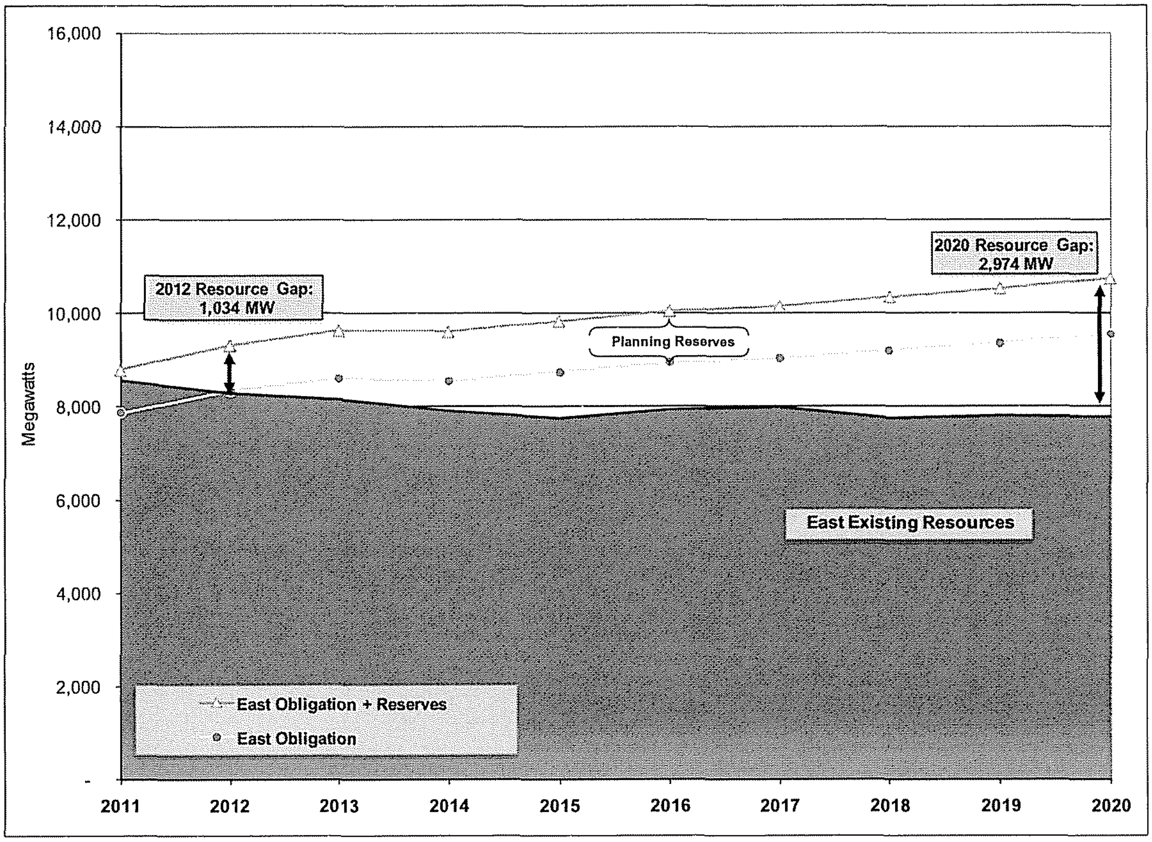


Figure 5.5 – East Capacity Position Trend



Energy Balance Determination

Methodology

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy. The on-peak hours are weekdays and Saturdays from hour-ending 7:00 am to 10:00 pm; off-peak hours are all other hours. Peaking resources such as the Gadsby units are counted only for the on-peak hours. This is calculated using the formulas that follow. Please refer to the section on load and resource balance components for details on how energy for each component is counted.

Existing Resources *= Thermal + Hydro + Class 1 DSM + Renewable + Firm Purchases + QF + Interruptible*

The average obligation is computed using the following formula:

Obligation *= Load + Sales*

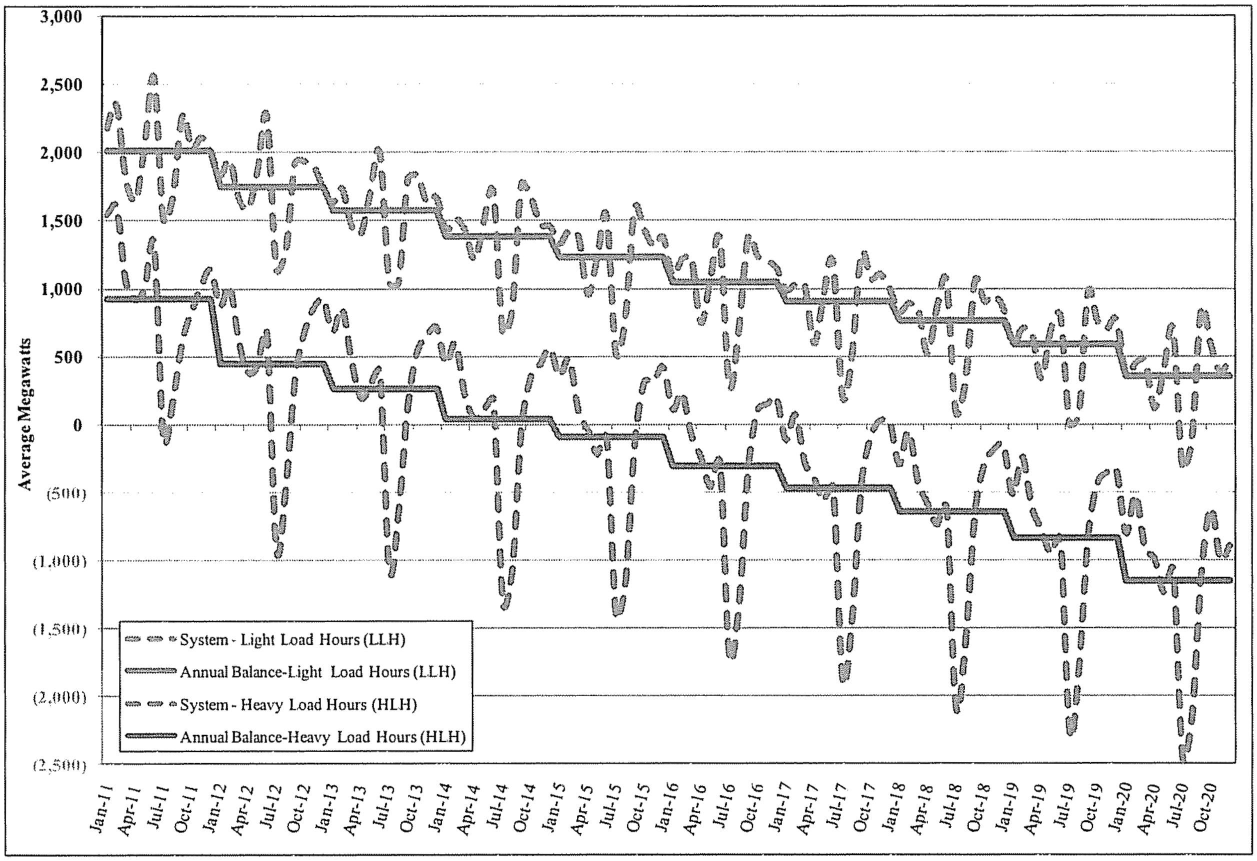
The energy position by month and daily time block is then computed as follows:

Energy Position *= Existing Resources – Obligation – Reserve Requirements (13 percent PRM)*

Energy Balance Results

Figures 5.6 through 5.8 show the energy balances for the system, west control area, and east control area, respectively. They indicate the energy balance on a monthly and annual average basis across heavy load hours and light load hours.[38] The monthly cross-over point, where the system starts to become energy deficient during the summer is 2011.

Figure 5.6 – System Average Monthly and Annual Energy Positions



[38] Heavy load hours constitute the daily time block of 16 hours, Hour-Ending 7 am – 10 pm, for Monday through Saturday, excluding NERC-observed holidays.

Figure 5.7 – West Average Monthly and Annual Energy Positions

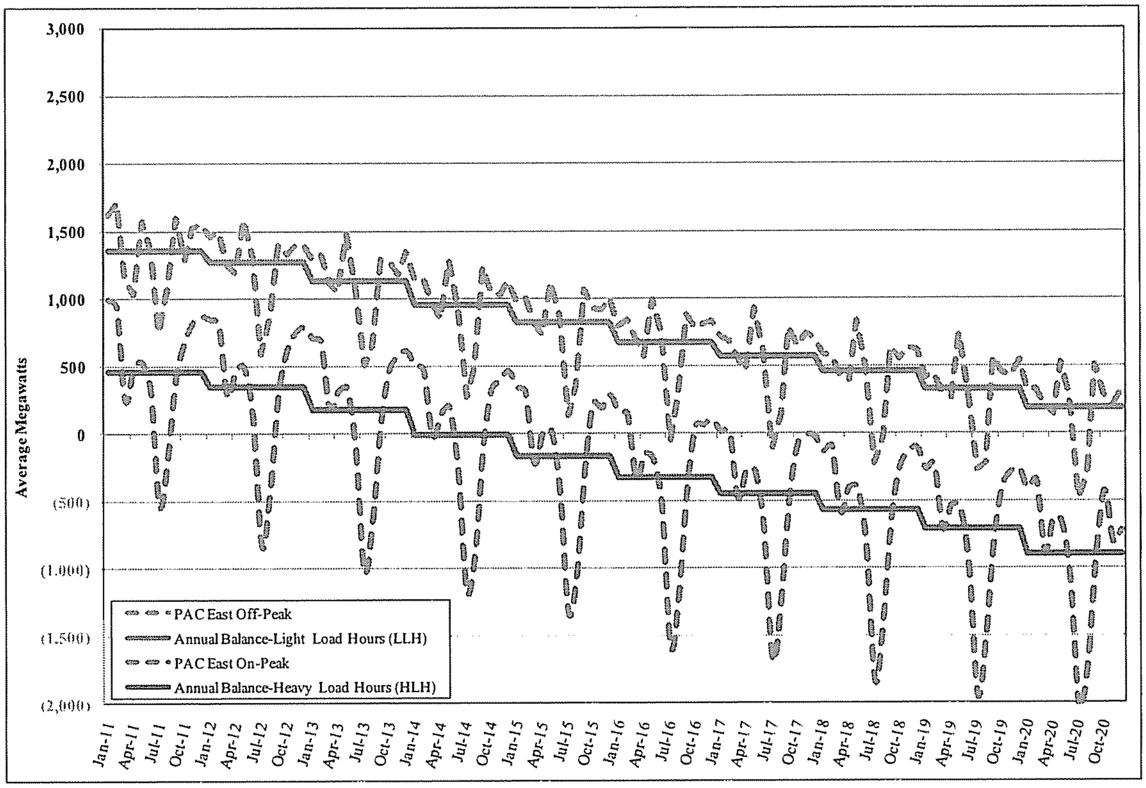
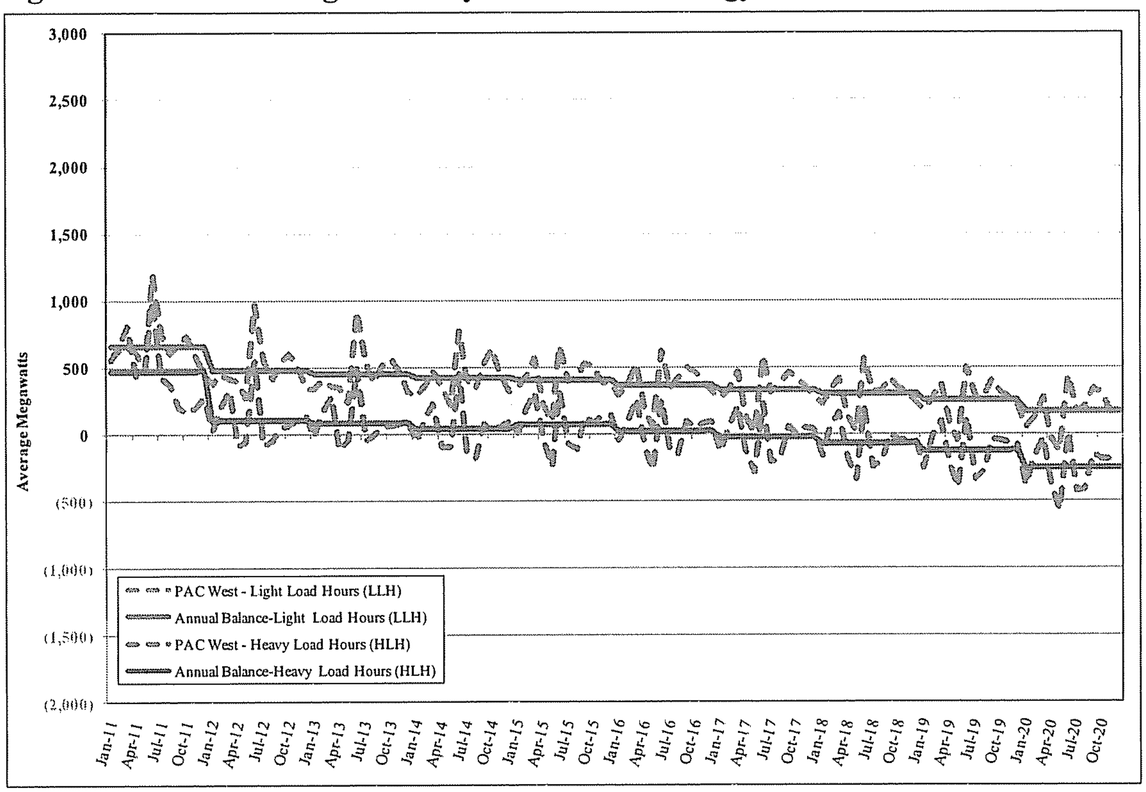


Figure 5.8 – East Average Monthly and Annual Energy Positions



Load and Resource Balance Conclusions

Without additional resources the Company projects a summer peak system resource deficit of 326 MW beginning in 2011. The near-term deficit will be filled by additional DSM programs, renewables, and market purchases. The Company will consider other options during this time frame if they are cost-effective and provide other system benefits. Then, beginning 2014, base load and/or intermediate load resource additions will be necessary to cover the widening capacity deficit.

CHAPTER 6 – RESOURCE OPTIONS

Chapter Highlights

- *PacifiCorp developed resource attributes and costs for expansion resources that reflect updated information from project experience, public meeting comments, and studies. Capital cost uncertainty for many of the proposed generation options is high and is due to such factors as labor cost, commodity price, and resource demand volatility. Long-term resource pricing remains a challenge to predict.*
- *Resource costs have generally decreased from the previous IRP due to the economic slow-down in 2009 and 2010.*
- *Wind resources have been modeled using an approach that more closely aligns with Western Renewable Energy Zones and facilitates assignment of incremental transmission costs for the Energy Gateway transmission scenario analysis.*
- *Solar generation options (utility-scale photovoltaic systems and solar thermal with and without thermal storage) have been included in this IRP.*
- *In 2010, the Company commissioned a geothermal resource study performed by Black & Veatch and GeothermEx that identified eight sites meeting specific criteria for commercial viability. PacifiCorp used this resource data to develop geothermal resource capacity expansion options. Geothermal resource costs include development costs reflecting dry well risk, amounting to 35 percent of total project costs.*
- *Energy storage systems continue to be of interest with options included for advanced large batteries (one megawatt) as well as pumped hydro and compressed air energy storage.*
- *A 2010 resource potential study, conducted by The Cadmus Group, served as the basis for updated resource characterizations covering demand-side management (DSM) and distributed generation. The demand-side resource information was converted into supply curves by program/product type and competed against other resource alternatives in IRP modeling.*
- *PacifiCorp applied cost reduction credits for energy efficiency, reflecting risk mitigation benefits, transmission & distribution investment deferral benefits, and a 10% market price credit for Washington as required by the Northwest Power Act.*

Introduction

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of supply-side generation (utility-scaled and distributed resources), DSM programs, transmission expansion projects, and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures.

Supply-side Resources

Resource Selection Criteria

The list of supply-side resource options has been modified in relation to previous IRP resource lists to reflect the realities evidenced through permitting, public meeting comments, and studies undertaken to better understand the details of available generation resources. Capital costs, in general have decreased due to the slow-down of the economy in 2009 and 2010. Based on information, from outside sources, including proprietary data from Cambridge Energy Research Associates (CERA) and Gas Turbine World, as well as internal studies, the prices of single and combined-cycle gas turbine plants have declined in recent years but, are recovering slowly. Alternative energy resources continue to receive a greater emphasis. Specifically additional solar generation options and geothermal options have been included in the analysis compared to the previous IRP. Additional solar resources include utility-size photovoltaic systems (PV) as well as solar thermal with and without thermal storage. Energy storage systems continue to be of interest with options included for advanced large batteries (1 MW) as well as traditional pumped hydro and compressed air energy storage.

Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2007 IRP. This resource list was reviewed and modified to reflect public input and permitting realities. Once the basic list of resources was determined, the cost and performance attributes for each resource were estimated. A number of information sources were used to identify parameters needed to model these resources. Supporting utility-scale resources were a number of engineering studies conducted by PacifiCorp to understand the cost of coal and gas resources in recent years. Additionally, experience with the construction of the 2x1 combined cycle plants at Currant Creek and Lake Side as well as other recent simple-cycle projects at Gadsby provided PacifiCorp with a detailed understanding of the cost of new power generating facilities. Preparation of benchmark submittals for PacifiCorp's recent generation RFPs were also used to update actual project experience, while government studies were relied upon for characterizing future carbon capture costs.

Extensive new studies on the cost of the coal-fired options were not prepared in keeping with the reduced emphasis on these resources for new near-term generation.

The results of these estimating efforts were compared with other cost databases, such as the one supporting the Integrated Planning Model (IPM®) market model developed by ICF International, which the Company now uses for national emissions policy impact analysis among other uses. The IPM® cost estimates were used when cost agreement was close.

The Company made use of The WorleyParsons Group's renewable generation study completed in 2008 for solar, biomass and geothermal resources. As described below, a geothermal resource study was conducted for the Company by Black & Veatch/GeothermEx in 2010 to supplement geothermal information for the third expansion at Blundell and other potential resources.

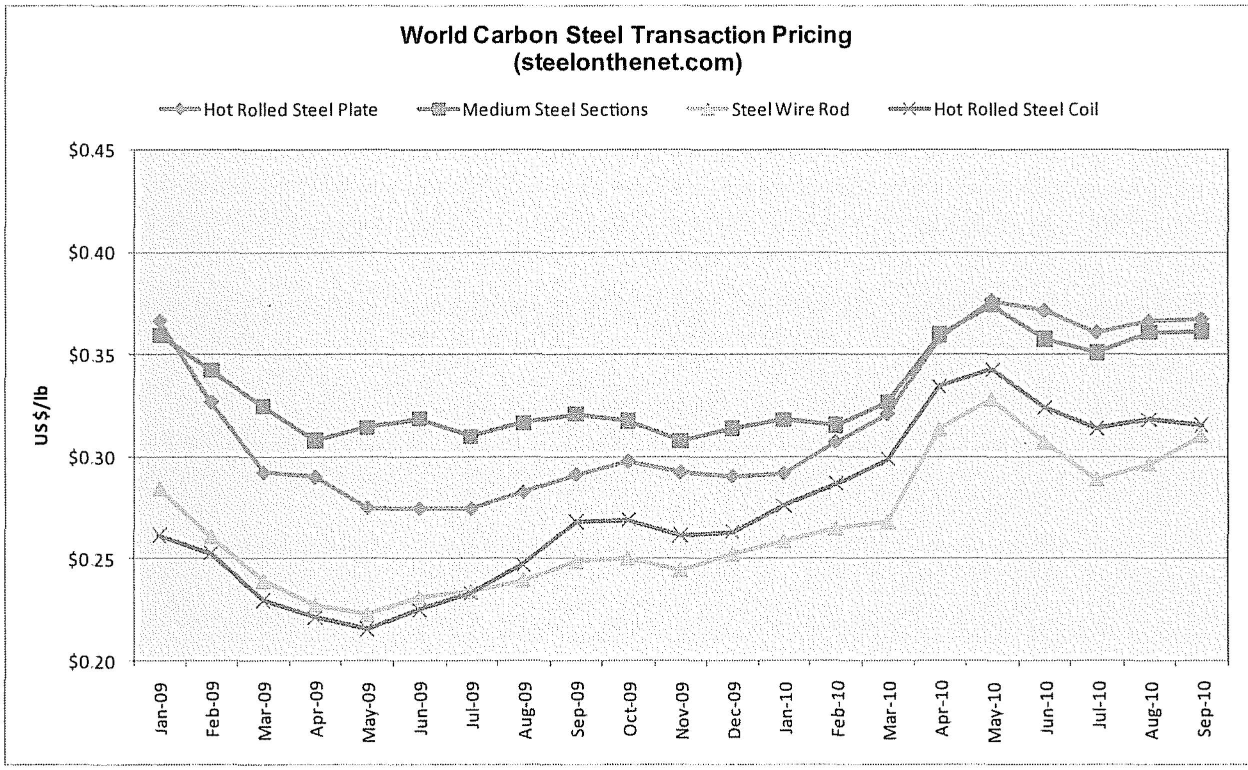
Wind costs are based on actual project experience in both the Pacific Northwest and Wyoming, as well as current projections. Nuclear costs are reflective of recent cost estimates associated with preliminary development activities as well as published estimates of new projects. Hydrokinetic, or wave power, has been added based on proposed projects in the Pacific Northwest. Other generation options, such as energy storage and fuel cells, were adopted from PacifiCorp's previous IRP. In some cases costs from the previous IRP were updated using cost increases for other studied resources.

Resource options also include a variety of small-scale generation resources, consisting of combined heat and power (CHP) and onsite solar supply-side resource options. Together these small resources are referred to as distributed generation. The Cadmus Group, Inc. (previously named Quantec LLC) provided the distributed generation costs and attributes as part of the DSM potential study update conducted for PacifiCorp in 2010. The DSM potential report identified the economic potential for distributed generation resources by state.

Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for many of the proposed generation options is high. Various factors contribute to this uncertainty. Previously experienced shortages of skilled labor are not a problem in the current business climate but volatile commodity prices are still a large part of the uncertainty in being able to predict project costs for lump-sum contracting. For example, Figure 6.1 shows the trend in North American carbon steel sheet prices. The volatility trend is expected to continue, although prices have trended upward in the last year.

Figure 6.1 – World Carbon Steel Price Trends



Some technologies that have seen a decrease in demand, such as wind turbines and coal, have seen significant cost decreases since the 2008 IRP. As such, subsequent to completion of its 2008 IRP portfolio analysis in late 2008 and early 2009, the Company has witnessed price declines for wind turbines and certain other power plant equipment. Other technologies still in demand, such as gas turbines, have seen more stable prices. Thus, long-term resource pricing remains challenging to forecast.

Technologies, such as the integrated gasification combined cycle (IGCC) and certain renewables, like solar, have greater price and operational uncertainty because only a few units have been built and operated. As these technologies mature and more plants are built and operated the costs of such new technologies may decrease relative to more mature options such as pulverized coal and conventional natural gas-fired plants.

The supply-side resource options tables below do not consider the potential for such savings since the benefits are not expected to be realized until the next generation of new plants are built and operated for a period of time. Any such benefits for IGCC facilities are not expected to be available until after 2025 with commercial operation in 2030. As such, future IRPs will be better able to incorporate the potential benefits of future cost reductions. Given the current emphasis on renewable generation, the Company anticipates the cost benefits for these technologies to be available sooner. The estimated capital costs are displayed in the supply-side resource tables along with expected availability of each technology for commercial utilization.

Resource Options and Attributes

Tables 6.2 and 6.3 present cost and performance attributes for supply-side resource options designated for PacifiCorp's east and west control areas, respectively. Tables 6.4 through 6.7 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2010 dollars. The resource costs are presented for the modeled CO_2 tax levels in recognition of the uncertainty in characterizing these emission costs.

As mentioned previously, the attributes were mainly derived from PacifiCorp's recent cost studies and project experience. Cost and performance values reflect analysis concluded by June 2010. Additional explanatory notes for the tables are as follows:

- Capital costs are intended to be all-inclusive, and account for Allowance for Funds Used During Construction (AFUDC), land, EPC (Engineering, Procurement, and Construction) cost premiums, owner's costs, etc. Capital costs in Tables 6.3 and 6.4 reflect mid-2010 dollars, and do not include escalation from mid year to the year of commercial operation.
- Wind sites are modeled with location-specific peak load carrying capability levels and capacity factors.
- Certain resource names are listed as acronyms. These include:
  PC – pulverized coal
  IGCC – integrated gasification combined cycle
  SCCT – simple cycle combustion turbine
  CCCT – combined cycle combustion turbine
  CHP – combined heat and power (cogeneration)
  CCS – carbon capture and sequestration
- PacifiCorp's September 2010 forward price curves were used to calculate the levelized fuel costs reported in Tables 6.4 through 6.7.
- Utility-scale solar resources include federal production tax credits. Hybrid solar with natural gas backup is also treated this way.
- PacifiCorp assumes that wind, hydrokinetic, biomass, and geothermal resources are qualified for Production Tax Credits (PTC), depending on the installation date. The cost of these credits is included in the supply-side table.
- Gas backup for solar with a heat rate of 11,750 Btu/kWh is less efficient than for a standalone SCCT.
- Capital costs include transmission interconnection costs (switchyard and other upgrades needed to interconnect the resource to PacifiCorp's transmission network).
- For the nuclear resource, capital costs include the cost of storing spent fuel on-site during the life of the facility. Costs for ultimate off-site disposal of spent fuel is not included since there are no details regarding where, when or how that will be done. While the reported capital cost does not reflect the cost of transmission, PacifiCorp adjusted the modeled capital cost to include transmission assuming a plant location near Payette, Idaho. The transmission cost adder is $842/kW, and factors in transmission lines and termination points for connections to the Hemingway and Limber substations.

- The capacity degradation of retrofitting an existing 500 MW pulverized coal unit with a carbon capture and sequestration (CCS) system represents the net change to capacity. The heat rate is the total net heat rate after retrofitting an existing 10,000 Btu/kWh unit with a CCS system.
- The wind resources are representative generic resources included in the IRP models for planning purposes. Cost and performance attributes of specific resources are identified as part of the acquisition process. An estimate for wind integration costs, $9.70/MWh, has been added in Tables 6.3 through 6.6.
- State specific tax benefits are excluded from the IRP supply side table but would be considered in the evaluation of a specific project.

Table 6.1 – East Side Supply-Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2010 Dollars ($)	Location / Timing		Plant Details			Outage Information		Costs			Emissions			
Resource Description	Installation Location	Earliest In-Service Date (Middle of year)	Average Capacity MW - Not Incl. Degradation	Design Plant Life in Years	Annual Average Heat Rate HHV - Incl. Degradation	Maint. Outage Rate	Equivalent Forced Outage Rate	Base Capital Cost in $/kW	Var. O&M, $/MWh	Fixed O&M in $/kW-yr	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu
East Side Resource Options														
Coal														
Utah PC without Carbon Capture & Sequestration	Utah	2020	600	40	9,106	4.6%	4.0%	$3,077	$0.96	$38.80	0.100	0.070	0.40	205
Utah PC with Carbon Capture & Sequestration	Utah	2030	526	40	13,087	5.0%	5.0%	$5,563	$6.71	$66.07	0.050	0.020	0.20	20
Utah IGCC with Carbon Capture & Sequestration	Utah	2030	466	40	10,823	7.0%	8.0%	$5,386	$11.28	$53.24	0.050	0.011	0.04	20
Wyoming PC without Carbon Capture & Sequestration	Wyoming	2020	790	40	9,214	4.6%	4.0%	$3,484	$1.27	$36.00	0.100	0.070	0.60	205
Wyoming PC with Carbon Capture & Sequestration	Wyoming	2030	692	40	13,242	5.0%	5.0%	$6,299	$7.26	$61.37	0.050	0.020	0.30	20
Wyoming IGCC with Carbon Capture & Sequestration	Wyoming	2030	456	40	11,047	7.0%	8.0%	$6,099	$13.52	$58.00	0.050	0.011	0.06	20
Existing PC with Carbon Capture & Sequestration (500 MW)	Utah/Wyo	2030	(139)	20	14,372	5.0%	5.0%	$1,383	$6.71	$66.07	0.050	0.011	0.30	20
Natural Gas (4500 feet)														
Utility Cogeneration	Utah	2014	10	20	4,974	10.0%	8.0%	$4,250	$23.29	$1.86	0.0006	0.050	0.255	118
Fuel Cell - Large (solid oxide fuel cell)	Utah	2013	5	30	7,262	2.0%	3.0%	$1,593	$0.03	$8.40	0.0006	0.050	0.255	118
SCCT Aero	Utah	2014	118	30	9,773	3.8%	2.6%	$1,000	$5.63	$9.95	0.0006	0.011	0.255	118
Intercooled Aero SCCT (Utah, 186 MW)	Utah	2014	279	30	9,379	3.8%	2.9%	$1,174	$3.93	$7.01	0.0006	0.011	0.255	118
Intercooled Aero SCCT (Utah, 279 MW)	Utah	2014	279	30	9,379	3.8%	2.9%	$1,174	$3.93	$7.01	0.0006	0.011	0.255	118
Intercooled Aero SCCT (Wyoming, 257 MW)	Wyoming	2014	257	30	9,379	3.8%	2.9%	$1,273	$4.26	$7.60	0.0006	0.011	0.255	118
Internal Combustion Engines	Utah	2014	301	30	8,806	5.0%	1.0%	$1,150	$5.50	$6.49	0.0006	0.017	0.255	118
SCCT Frame (2 Frame "F")	Utah	2014	362	35	10,446	3.8%	2.7%	$991	$7.16	$5.41	0.0006	0.050	0.255	118
SCCT Frame (2 Frame "F")	Wyoming	2014	330	35	10446	3.8%	2.7%	$1,074	$7.76	$5.87	0.0006	0.050	0.255	118
CCCT (Wet "F" 1x1)	Utah	2014	270	40	7,302	3.8%	2.7%	$1,181	$2.98	$13.48	0.0006	0.011	0.255	118
CCCT Duct Firing (Wet "F" 1x1)	Utah	2014	43	40	8,869	3.8%	2.7%	$482	$0.55	$0.00	0.0006	0.011	0.255	118
CCCT (Wet "F" 2x1)	Utah	2014	539	40	6,885	3.8%	2.7%	$1,067	$2.98	$8.19	0.0006	0.011	0.255	118
CCCT Duct Firing (Wet "F" 2x1)	Utah	2014	86	40	8,681	3.8%	2.7%	$538	$0.55	$0.00	0.0006	0.011	0.255	118
CCCT (Dry "F" 2x1)	Utah	2015	512	40	6,963	3.8%	2.7%	$1,104	$3.35	$9.69	0.0006	0.011	0.255	118
CCCT Duct Firing (Dry "F" 2x1)	Utah	2015	85	40	8,934	3.8%	2.7%	$538	$0.55	$0.00	0.0006	0.011	0.255	118
CCCT (Wet "G" 1x1)	Utah	2015	333	40	6,751	3.8%	2.7%	$1,117	$4.56	$6.75	0.0006	0.011	0.255	118
CCCT Duct Firing (Wet "G" 1x1)	Utah	2015	72	40	9,021	3.8%	2.7%	$473	$0.36	$0.00	0.0006	0.011	0.255	118
CCCT Advanced (Wet "H" 1x1)	Utah	2018	400	40	6,602	3.8%	2.7%	$1,233	$4.56	$6.75	0.0006	0.011	0.255	118
CCCT Advanced Duct Firing (Wet "H" 1x1)	Utah	2018	75	40	9,021	3.8%	2.7%	$605	$0.36	$0.00	0.0006	0.011	0.255	118
Other - Renewables														
Wyoming Wind (35% CF)	Wyoming	2012	100	25	n/a	n/a	n/a	$2,239	$0.00	$31.43	0.000	0.000	0.000	0
Utah Wind (29% CF)	Utah	2012	100	25	n/a	n/a	n/a	$2,239	$0.00	$31.43	0.000	0.000	0.000	0
Blundell Geothermal (Dual Flash)	Utah	2015	35	40	n/a	5.0%	5.0%	$4,277	$5.94	$110.85	0.000	0.000	0.000	0
Greenfield Geothermal (Binary)	Utah	2017	45	40	n/a	5.0%	5.0%	$6,132	$5.94	$209.40	0.000	0.000	0.000	0
Advance Battery Storage	All	2015	5	30	11,000	1.9%	5.0%	$2,025	$10.00	$1.00	0.100	0.400	3.000	205
Pumped Storage	Nevada	2020	250	50	12,500	5.0%	5.0%	$1,723	$4.30	$4.30	0.100	0.400	3.000	205
Compressed Air Energy Storage (CAES)	Wyoming	2015	350	30	11,980	3.8%	2.7%	$1,307	$5.50	$3.80	0.001	0.011	0.255	118
Nuclear (Advance Fission)	Idaho	2030	1,600	40	10,710	7.3%	7.7%	$5,307	$1.63	$146.70	0.000	0.000	0.000	0
Solar (Thin Film PV) - 19% CF	Utah	2012	5	25	n/a	n/a	n/a	$4,191	$0.00	$59.50	0.000	0.000	0.000	0
Solar Concentrating (Thermal Trough, NG backup) - 25% solar	Utah	2014	250	30	n/a	n/a	n/a	$4,033	$0.00	$120.99	0.000	0.000	0.000	0
Solar Concentrating (Thermal Trough) - 30% solar	Utah	2014	250	30	n/a	n/a	n/a	$4,519	$0.00	$135.56	0.000	0.000	0.000	0

Table 6.2 – West Side Supply-Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2010 Dollars ($)	Location / Timing		Plant Details			Outage Information		Costs			Emissions			
Resource Description	Installation Location	Earliest In-Service Date (Middle of year)	Average Capacity MW - Not Incl. Degradation	Design Plant Life in Years	Annual Average Heat Rate HHV - Incl. Degradation	Maint. Outage Rate	Equivalent Forced Outage Rate	Base Capital Cost in $/kW	Var. O&M, $/MWh	Fixed O&M in $/kW-yr	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu
West Side Resource Options														
Natural Gas (4500 feet)														
CCCT (Wet "F" 2xl)	Northwest	2014	539	40	6,885	3.8%	2.7%	$1,067	$2.98	$8.19	0.0006	0.011	0.255	118
CCCT Duct Firing (Wet "F" 2xl)	Northwest	2014	86	40	8,681	3.8%	2.7%	$538	$0.55	$0.00	0.0006	0.011	0.255	118
CCCT (Wet "G" 1xl)	Northwest	2015	333	40	6,751	3.8%	2.7%	$1,117	$4.56	$6.75	0.0006	0.011	0.255	118
CCCT Duct Firing (Wet "G" 1xl)	Northwest	2015	72	40	9,021	3.8%	2.7%	$473	$0.36	$0.00	0.0006	0.011	0.255	118
CCCT Advanced (Wet "H" 1xl)	Northwest	2018	400	40	6,602	3.8%	2.7%	$1,233	$4.56	$6.75	0.0006	0.011	0.255	118
CCCT Advanced Duct Firing (Wet "H" 1xl)	Northwest	2018	75	40	9,021	3.8%	2.7%	$605	$0.36	$0.00	0.0006	0.011	0.255	118
Natural Gas (1500 feet)														
Fuel Cell - Large (solid oxide fuel cell)	Northwest	2013	5	30	7,262	2.0%	3.0%	$1,593	$0.03	$8.40	0.0006	0.050	0.255	118
SCCT Aero	Northwest	2014	130	30	9,773	3.85%	2.60%	$909	$5.12	$9.04	0.00060	0.01102	0.255	118
Intercooled Aero SCCT	Northwest	2014	307	30	9,379	3.85%	2.90%	$1,067	$3.57	$6.37	0.00060	0.01102	0.255	118
Internal Combustion Engines	Northwest	2014	331	30	8,806	5.00%	1.00%	$1,046	$5.50	$6.49	0.00060	0.01652	0.255	118
SCCT Frame (2 Frame "F")	Northwest	2014	405	35	10,446	3.85%	2.70%	$901	$6.51	$4.92	0.00060	0.04950	0.255	118
Other - Renewables														
Oregon / Washington Wind (29% CF)	Northwest	2012	50	25	n/a	n/a	5.00%	$2,383	$0.00	$31.43	0.00000	0.000	0.0	0
Greenfield Geothermal (Binary)	Northwest	2015	35	40	n/a	5.00%	5.00%	$6,132	$5.94	$209.40	0.00000	0.000	0.0	0
Biomass	Northwest	2015	50	30	10,979	4.60%	4.00%	$3,509	$0.96	$38.80	0.1000	0.3500	0.400	205
Hydrokinetic (Wave, Buoy) - 21% CF	Northwest	2020	100	20	n/a	n/a	n/a	$5,831	$0.00	174.92	0.0000	0.0000	0.000	0
Solar (Thin Film PV) - 19% CF	Northwest	2012	5	25	n/a	n/a	n/a	$4,191	0	$56.91	0	0	0	0
West Side Resource Options at ISO Conditions (Sea Level)														
Natural Gas														
CCCT (Wet "F" 2xl)	Northwest	2014	620	40	6,885	3.85%	2.70%	$928	$2.59	$7.12	0.00060	0.0110	0.255	118
CCCT Duct Firing (Wet "F" 2xl)	Northwest	2014	99	40	8,681	3.85%	2.70%	$468	$0.48	$0.00	0.00060	0.0110	0.255	118

Table 6.3 – Total Resource Cost for East Side Supply-Side Resource Options, \$0 CO_2 Tax

\$0 CO2 Tax	Capital Cost \$/kW			Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)					
Supply Side Resource Options Mid-Calendar Year 2010 Dollars (\$)				Fixed O&M \$/kW-Yr						Levelized Fuel							
Resource Description	Total Capital Cost	Payment Factor	Annual Payment (\$/kW-Yr)	O&M	Other	Total	Total Fixed (\$/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Tax Credits	Environmental	Total Resource Cost with PTC (Mills/kWh)	Total Resource Cost without PTC (Mills/kWh)
East Side Resource Options																	
Coal																	
Utah PC without Carbon Capture & Sequestration	\$ 3,077	8.18%	\$ 251.66	\$ 38.80	\$ 6.00	\$ 44.80	\$ 296.46	91%	37.03	254.41	23.17	\$ 0.96	-	-	0.00	61.15	
Utah PC with Carbon Capture & Sequestration	\$ 5,563	8.02%	\$ 445.91	\$ 66.07	\$ 6.00	\$ 72.07	\$ 517.98	90%	65.70	254.41	33.29	\$ 6.71	-	-	0.00	105.70	
Utah IGCC with Carbon Capture & Sequestration	\$ 5,386	7.90%	\$ 425.60	\$ 53.24	\$ 6.00	\$ 59.24	\$ 484.84	85%	65.11	254.41	27.54	\$ 11.28	-	-	0.00	103.93	
Wyoming PC without Carbon Capture & Sequestration	\$ 3,484	8.18%	\$ 284.95	\$ 36.00	\$ 6.00	\$ 42.00	\$ 326.95	91%	40.84	247.56	22.81	\$ 1.27	-	-	0.00	64.92	
Wyoming PC with Carbon Capture & Sequestration	\$ 6,299	8.02%	\$ 504.90	\$ 61.37	\$ 6.00	\$ 67.37	\$ 572.27	90%	72.59	247.56	32.78	\$ 7.26	-	-	0.00	112.63	
Wyoming IGCC with Carbon Capture & Sequestration	\$ 6,099	7.90%	\$ 481.91	\$ 58.00	\$ 6.00	\$ 64.00	\$ 545.91	85%	73.32	247.56	27.35	\$ 13.52	-	-	0.00	114.18	
Existing PC with Carbon Capture & Sequestration (500 MW)	\$ 1,383	10.50%	\$ 145.16	\$ 66.07	\$ 6.00	\$ 72.07	\$ 217.23	90%	27.55	247.56	35.58	\$ 6.71	-	-	0.00	69.84	
Natural Gas (4500 feet)																	
Utility Cogeneration	\$ 4,250	9.91%	\$421.23	\$ 1.86	\$ 0.50	\$ 2.36	\$ 423.59	82%	58.97	539.00	26.81	\$ 23.29	\$ 3.33	-	0.00	112.40	
Fuel Cell - Large (solid oxide fuel cell)	\$ 1,593	8.55%	\$136.15	\$ 8.40	\$ 0.50	\$ 8.90	\$ 145.05	95%	17.43	539.00	39.14	\$ 0.03	\$ 4.87	-	0.00	61.47	
SCCT Aero	\$ 1,000	8.88%	\$88.77	\$ 9.95	\$ 0.50	\$ 10.45	\$ 99.22	21%	53.94	539.00	52.68	\$ 5.63	\$ 6.55	-	0.00	118.79	
Intercooled Aero SCCT (Utah, 186 MW)	\$ 1,174	8.88%	\$104.25	\$ 7.01	\$ 0.50	\$ 7.51	\$ 111.76	21%	60.75	539.00	50.55	\$ 3.93	\$ 6.28	-	0.00	121.52	
Intercooled Aero SCCT (Utah, 279 MW)	\$ 1,174	8.88%	\$104.25	\$ 7.01	\$ 0.50	\$ 7.51	\$ 111.76	21%	60.75	539.00	50.55	\$ 3.93	\$ 6.28	-	0.00	121.52	
Intercooled Aero SCCT (Wyoming, 257 MW)	\$ 1,273	8.88%	\$113.04	\$ 7.60	\$ 0.50	\$ 8.10	\$ 121.14	21%	65.85	539.00	50.55	\$ 4.26	\$ 5.46	-	0.00	126.12	
Internal Combustion Engines	\$ 1,150	8.88%	\$102.11	\$ 6.49	\$ 0.50	\$ 6.99	\$ 109.10	21%	59.30	539.00	47.46	\$ 5.50	\$ 5.90	-	0.00	118.17	
SCCT Frame (2 Frame "F")	\$ 991	8.41%	\$83.36	\$ 5.41	\$ 0.50	\$ 5.91	\$ 89.27	21%	48.53	539.00	56.30	\$ 7.16	\$ 7.00	-	0.00	118.99	
SCCT Frame (2 Frame "F")	\$ 1,074	8.41%	\$90.39	\$ 5.87	\$ 0.50	\$ 6.37	\$ 96.76	21%	52.60	539.00	56.30	\$ 7.76	\$ 6.08	-	0.00	122.75	
CCCT (Wet "F" 1x1)	\$ 1,181	8.37%	\$98.92	\$ 13.48	\$ 0.50	\$ 13.98	\$ 112.90	56%	23.01	539.00	39.36	\$ 2.98	\$ 4.89	-	0.00	70.25	
CCCT Duct Firing (Wet "F" 1x1)	\$ 482	8.37%	\$40.37	-	\$ 0.50	\$ 0.50	\$ 40.87	16%	29.16	539.00	47.80	\$ 0.55	\$ 5.94	-	0.00	83.46	
CCCT (Wet "F" 2x1)	\$ 1,067	8.37%	\$89.34	\$ 8.19	\$ 0.50	\$ 8.69	\$ 98.04	56%	19.98	539.00	37.11	\$ 2.98	\$ 4.61	-	0.00	64.69	
CCCT Duct Firing (Wet "F" 2x1)	\$ 538	8.37%	\$45.08	-	\$ 0.50	\$ 0.50	\$ 45.58	16%	32.52	539.00	46.79	\$ 0.55	\$ 5.82	-	0.00	85.68	
CCCT (Dry "F" 2x1)	\$ 1,104	8.37%	\$92.48	\$ 9.69	\$ 0.50	\$ 10.19	\$ 102.67	56%	20.93	539.00	37.53	\$ 3.35	\$ 4.67	-	0.00	66.48	
CCCT Duct Firing (Dry "F" 2x1)	\$ 538	8.37%	\$45.08	-	\$ 0.50	\$ 0.50	\$ 45.58	16%	32.52	539.00	48.15	\$ 0.55	\$ 5.99	-	0.00	87.21	
CCCT (Wet "G" 1x1)	\$ 1,117	8.37%	\$93.53	\$ 6.75	\$ 0.50	\$ 7.25	\$ 100.78	56%	20.54	539.00	36.39	\$ 4.56	\$ 4.52	-	0.00	66.01	
CCCT Duct Firing (Wet "G" 1x1)	\$ 473	8.37%	\$39.60	-	\$ 0.50	\$ 0.50	\$ 40.10	16%	28.61	539.00	48.62	\$ 0.36	\$ 6.04	-	0.00	83.63	
CCCT Advanced (Wet "H" 1x1)	\$ 1,233	8.37%	\$103.28	\$ 6.75	\$ 0.50	\$ 7.25	\$ 110.53	56%	22.53	539.00	35.58	\$ 4.56	\$ 4.42	-	0.00	67.09	
CCCT Advanced Duct Firing (Wet "H" 1x1)	\$ 605	8.37%	\$50.68	-	\$ 0.50	\$ 0.50	\$ 51.18	16%	36.51	539.00	48.62	\$ 0.36	\$ 6.04	-	0.00	91.54	
Other - Renewables																	
Wyoming Wind (35% CF)	\$ 2,239	8.55%	\$191.33	\$ 31.43	\$ 0.50	\$ 31.93	\$ 223.26	35%	72.82	-	-	-	\$ 9.70	(20.69)	-	61.82	82.52
Utah Wind (29% CF)	\$ 2,239	8.55%	\$191.33	\$ 31.43	\$ 0.50	\$ 31.93	\$ 223.26	29%	87.88	-	-	-	\$ 9.70	(20.69)	-	76.89	97.58
Blundell Geothermal (Dual Flash)	\$ 4,277	7.24%	\$309.68	\$ 110.85	\$ 0.50	\$ 111.35	\$ 421.03	90%	53.40	-	-	\$ 5.94		(20.69)	-	38.65	59.34
Greenfield Geothermal (Binary)	\$ 6,132	7.24%	\$444.03	\$ 209.40	\$ 0.50	\$ 209.90	\$ 653.93	90%	82.94	-	-	\$ 5.94		(20.69)	-	68.19	88.88
Advance Battery Storage	\$ 2,025	8.11%	\$164.34	\$ 1.00	\$ 0.50	\$ 1.50	\$ 165.84	21%	90.15	539.00	59.29	\$ 10.00	\$ 7.37	-	0.00	166.81	
Pumped Storage	\$ 1,723	7.97%	\$137.25	\$ 4.30	\$ 1.35	\$ 5.65	\$ 142.90	20%	81.56	539.00	67.38	\$ 4.30	\$ 8.41	-	0.00	161.65	
Compressed Air Energy Storage (CAES)	\$ 1,307	8.11%	\$106.02	\$ 3.80	\$ 1.35	\$ 5.15	\$ 111.17	47%	27.18	539.00	64.57	\$ 5.50	\$ 6.97	-	0.00	104.22	
Nuclear (Advance Fission)	\$ 5,307	8.09%	\$429.48	\$ 146.70	\$ 6.00	\$ 152.70	\$ 582.18	85%	78.19	81.14	8.69	\$ 1.63	-	-	-	88.50	88.50
Solar (Thin Film PV) - 19% CF	\$ 4,191	8.55%	\$358.24	\$ 59.50	\$ 6.00	\$ 65.50	\$ 423.74	19%	254.59	-	-	-	-	(20.69)	-	233.90	254.59
Solar Concentrating (Thermal Trough, NG backup) - 25% solar	\$ 4,033	9.53%	\$384.21	\$ 120.99	\$ 6.00	\$ 126.99	\$ 511.20	33%	176.84	539.00	14.62	-	\$ 1.82	(20.69)	-	172.58	193.27
Solar Concentrating (Thermal Trough) - 30% solar	\$ 4,519	7.93%	\$358.43	\$ 135.56	\$ 6.00	\$ 141.56	\$ 499.99	30%	190.26	-	-	-	\$ 1.82	(20.69)	-	171.38	192.07

Table 6.4 – Total Resource Cost for West Side Supply-Side Resource Options, \$0 CO_2 Tax

\$0 CO2 Tax	Capital Cost \$/kW			Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)					
Supply Side Resource Options Mid-Calendar Year 2010 Dollars (\$)				Fixed O&M \$/kW-Yr						Levelized Fuel							
Resource Description	Total Capital Cost	Payment Factor	Annual Payment (\$/kW-Yr)	O&M	Other	Total	Total Fixed (\$/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Tax Credits	Environmental	Total Resource Cost with PTC (Mills/kWh)	Total Resource Cost without PTC (Mills/kWh)
West Side Resource Options																	
Natural Gas (4500 feet)																	
CCCT (Wet "F" 2x1)	\$ 1,067	8.37%	\$89.34	\$ 8.19	\$ 0.50	\$ 8.69	\$ 98.04	56%	19.98	572.00	39.38	\$ 2.98	\$ 4.85	-	0.00	67.20	
CCCT Duct Firing (Wet "F" 2x1)	\$ 538	8.37%	\$45.08	-	\$ 0.50	\$ 0.50	\$ 45.58	16%	32.52	572.00	49.65	\$ 0.55	\$ 6.12	-	0.00	88.84	
CCCT (Wet "G" 1x1)	\$ 1,117	8.37%	\$93.53	\$ 6.75	\$ 0.50	\$ 7.25	\$ 100.78	56%	20.54	572.00	38.62	\$ 4.56	\$ 4.76	-	0.00	68.48	
CCCT Duct Firing (Wet "G" 1x1)	\$ 473	8.37%	\$39.60	-	\$ 0.50	\$ 0.50	\$ 40.10	16%	28.61	572.00	51.60	\$ 0.36	\$ 6.36	-	0.00	86.93	
CCCT Advanced (Wet "H" 1x1)	\$ 1,233	8.37%	\$103.28	\$ 6.75	\$ 0.50	\$ 7.25	\$ 110.53	56%	22.53	572.00	37.76	\$ 4.56	\$ 4.65	-	0.00	69.50	
CCCT Advanced Duct Firing (Wet "H" 1x1)	\$ 605	8.37%	\$50.68	-	\$ 0.50	\$ 0.50	\$ 51.18	16%	36.51	572.00	51.60	\$ 0.36	\$ 6.36	-	0.00	94.83	
Natural Gas (1500 feet)																	
Fuel Cell - Large (solid oxide fuel cell)	\$ 1,593	8.55%	\$136.15	\$ 8.40	\$ 0.50	\$ 8.90	\$ 145.05	95%	17.43	572.00	41.54	\$ 0.03	\$ 5.12	-	0.00	64.12	
SCCT Aero	\$ 909	8.88%	\$80.70	\$ 9.04	\$ 0.50	\$ 9.54	\$ 90.25	21%	49.06	572.00	55.90	\$ 5.12	\$ 6.89	-	0.00	116.97	
Intercooled Aero SCCT	\$ 1,067	8.88%	\$94.77	\$ 6.37	\$ 0.50	\$ 6.87	\$ 101.64	21%	55.25	572.00	53.65	\$ 3.57	\$ 6.61	-	0.00	119.08	
Internal Combustion Engines	\$ 1,046	8.88%	\$92.82	\$ 6.49	\$ 0.50	\$ 6.99	\$ 99.81	21%	54.26	572.00	50.37	\$ 5.50	\$ 6.21	-	0.00	116.34	
SCCT Frame (2 Frame "F")	\$ 901	8.41%	\$75.78	\$ 4.92	\$ 0.50	\$ 5.42	\$ 81.20	21%	44.14	572.00	59.75	\$ 6.51	\$ 7.36	-	0.00	117.76	
Other - Renewables																	
Oregon / Washington Wind (29% CF)	\$ 2,383	8.55%	\$203.69	\$ 31.43	\$ 0.50	\$ 31.93	\$ 235.62	29%	92.75	-	-	-	\$ 9.70	(20.69)	-	81.75	102.45
Greenfield Geothermal (Binary)	\$ 6,132	7.24%	\$444.03	\$ 209.40	\$ 0.50	\$ 209.90	\$ 653.93	90%	82.94	-	-	\$ 5.94	-	(20.69)	-	68.19	88.88
Biomass	\$ 3,509	7.93%	\$278.36	\$ 38.80	\$ 0.50	\$ 39.30	\$ 317.66	91%	39.67	483.58	53.09	\$ 0.96	-	(20.69)	0.00	73.04	93.73
Hydrokinetic (Wave, Buoy) - 21% CF	\$ 5,831	9.53%	\$555.49	\$ 174.92	\$ 6.00	\$ 180.92	\$ 736.41	21%	400.31	-	-	-	-	(20.69)	-	379.61	400.31
Solar (Thin Film PV) - 19% CF	\$ 4,191	8.55%	\$358.24	\$ 56.91	\$ 6.00	\$ 62.91	\$ 421.16	19%	253.04	-	-	-	-	(20.69)	-	232.34	253.04
West Side Resource Options																	
Natural Gas																	
CCCT (Wet "F" 2x1)	\$ 928	8.37%	\$77.69	\$ 7.12	\$ 0.50	\$ 7.62	\$ 85.31	56%	17.39	572.00	39.38	\$ 2.59	\$ 4.85	-	0.00	64.22	
CCCT Duct Firing (Wet "F" 2x1)	\$ 468	8.37%	\$39.20	-	\$ 0.50	\$ 0.50	\$ 39.70	16%	28.32	572.00	49.65	\$ 0.48	\$ 6.12	-	0.00	84.58	

Table 6.5 – Total Resource Cost for East Side Supply-Side Resource Options, $19 CO_2 Tax

$19 CO2 Tax	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)					
Supply Side Resource Options Mid-Calendar Year 2010 Dollars ($)				Fixed O&M $/kW-Yr						Levelized Fuel							
Resource Description	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Other	Total	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Tax Credits	Environmental	Total Resource Cost with PTC (Mills/kWh)	Total Resource Cost without PTC (Mills/kWh)
East Side Resource Options																	
Coal																	
Utah PC without Carbon Capture & Sequestration	$ 3,077	8.18%	$ 251.66	$ 38.80	$ 6.00	$ 44.80	$ 296.46	91%	37.03	254.41	23.17	$ 0.96	-	-	13.36	74.51	
Utah PC with Carbon Capture & Sequestration	$ 5,563	8.02%	$ 445.91	$ 66.07	$ 6.00	$ 72.07	$ 517.98	90%	65.70	254.41	33.29	$ 6.71	-	-	1.87	107.57	
Utah IGCC with Carbon Capture & Sequestration	$ 5,386	7.90%	$ 425.60	$ 53.24	$ 6.00	$ 59.24	$ 484.84	85%	65.11	254.41	27.54	$ 11.28	-	-	1.55	105.48	
Wyoming PC without Carbon Capture & Sequestration	$ 3,484	8.18%	$ 284.95	$ 36.00	$ 6.00	$ 42.00	$ 326.95	91%	40.84	247.56	22.81	$ 1.27	-	-	13.52	78.43	
Wyoming PC with Carbon Capture & Sequestration	$ 6,299	8.02%	$ 504.90	$ 61.37	$ 6.00	$ 67.37	$ 572.27	90%	72.59	247.56	32.78	$ 7.26	-	-	1.89	114.52	
Wyoming IGCC with Carbon Capture & Sequestration	$ 6,099	7.90%	$ 481.91	$ 58.00	$ 6.00	$ 64.00	$ 545.91	85%	73.32	247.56	27.35	$ 13.52	-	-	1.58	115.76	
Existing PC with Carbon Capture & Sequestration (500 MW)	$ 1,383	10.50%	$ 145.16	$ 66.07	$ 6.00	$ 72.07	$ 217.23	90%	27.55	247.56	35.58	$ 6.71	-	-	2.05	71.90	
Natural Gas (4500 feet)																	
Utility Cogeneration	$ 4,250	9.91%	$421.23	$ 1.86	$ 0.50	$ 2.36	$ 423.59	82%	58.97	539.00	26.81	$ 23.29	$ 3.33	-	4.19	116.59	
Fuel Cell - Large (solid oxide fuel cell)	$ 1,593	8.55%	$136.15	$ 8.40	$ 0.50	$ 8.90	$ 145.05	95%	17.43	539.00	39.14	$ 0.03	$ 4.87	-	6.12	67.59	
SCCT Aero	$ 1,000	8.88%	$88.77	$ 9.95	$ 0.50	$ 10.45	$ 99.22	21%	53.94	539.00	52.68	$ 5.63	$ 6.55	-	8.24	127.03	
Intercooled Aero SCCT (Utah, 186 MW)	$ 1,174	8.88%	$104.25	$ 7.01	$ 0.50	$ 7.51	$ 111.76	21%	60.75	539.00	50.55	$ 3.93	$ 6.28	-	7.91	129.42	
Intercooled Aero SCCT (Utah, 279 MW)	$ 1,174	8.88%	$104.25	$ 7.01	$ 0.50	$ 7.51	$ 111.76	21%	60.75	539.00	50.55	$ 3.93	$ 6.28	-	7.91	129.42	
Intercooled Aero SCCT (Wyoming, 257 MW)	$ 1,273	8.88%	$113.04	$ 7.60	$ 0.50	$ 8.10	$ 121.14	21%	65.85	539.00	50.55	$ 4.26	$ 5.46	-	7.91	134.03	
Internal Combustion Engines	$ 1,150	8.88%	$102.11	$ 6.49	$ 0.50	$ 6.99	$ 109.10	21%	59.30	539.00	47.46	$ 5.50	$ 5.90	-	7.42	125.59	
SCCT Frame (2 Frame "F")	$ 991	8.41%	$83.36	$ 5.41	$ 0.50	$ 5.91	$ 89.27	21%	48.53	539.00	56.30	$ 7.16	$ 7.00	-	8.81	127.80	
SCCT Frame (2 Frame "F")	$ 1,074	8.41%	$90.39	$ 5.87	$ 0.50	$ 6.37	$ 96.76	21%	52.60	539.00	56.30	$ 7.76	$ 6.08	-	8.81	131.55	
CCCT (Wet "F" 1x1)	$ 1,181	8.37%	$98.92	$ 13.48	$ 0.50	$ 13.98	$ 112.90	56%	23.01	539.00	39.36	$ 2.98	$ 4.89	-	6.16	76.40	
CCCT Duct Firing (Wet "F" 1x1)	$ 482	8.37%	$40.37	-	$ 0.50	$ 0.50	$ 40.87	16%	29.16	539.00	47.80	$ 0.55	$ 5.94	-	7.48	90.94	
CCCT (Wet "F" 2x1)	$ 1,067	8.37%	$89.34	$ 8.19	$ 0.50	$ 8.69	$ 98.04	56%	19.98	539.00	37.11	$ 2.98	$ 4.61	-	5.80	70.50	
CCCT Duct Firing (Wet "F" 2x1)	$ 538	8.37%	$45.08	-	$ 0.50	$ 0.50	$ 45.58	16%	32.52	539.00	46.79	$ 0.55	$ 5.82	-	7.32	93.00	
CCCT (Dry "F" 2x1)	$ 1,104	8.37%	$92.48	$ 9.69	$ 0.50	$ 10.19	$ 102.67	56%	20.93	539.00	37.53	$ 3.35	$ 4.67	-	5.87	72.35	
CCCT Duct Firing (Dry "F" 2x1)	$ 538	8.37%	$45.08	-	$ 0.50	$ 0.50	$ 45.58	16%	32.52	539.00	48.15	$ 0.55	$ 5.99	-	7.53	94.74	
CCCT (Wet "G" 1x1)	$ 1,117	8.37%	$93.53	$ 6.75	$ 0.50	$ 7.25	$ 100.78	56%	20.54	539.00	36.39	$ 4.56	$ 4.52	-	5.69	71.70	
CCCT Duct Firing (Wet "G" 1x1)	$ 473	8.37%	$39.60	-	$ 0.50	$ 0.50	$ 40.10	16%	28.61	539.00	48.62	$ 0.36	$ 6.04	-	7.61	91.24	
CCCT Advanced (Wet "H" 1x1)	$ 1,233	8.37%	$103.28	$ 6.75	$ 0.50	$ 7.25	$ 110.53	56%	22.53	539.00	35.58	$ 4.56	$ 4.42	-	5.57	72.66	
CCCT Advanced Duct Firing (Wet "H" 1x1)	$ 605	8.37%	$50.68	-	$ 0.50	$ 0.50	$ 51.18	16%	36.51	539.00	48.62	$ 0.36	$ 6.04	-	7.61	99.15	
Other - Renewables																	
Wyoming Wind (35% CF)	$ 2,239	8.55%	$191.33	$ 31.43	$ 0.50	$ 31.93	$ 223.26	35%	72.82	-	-	-	$ 9.70	(20.69)	-	61.82	82.52
Utah Wind (29% CF)	$ 2,239	8.55%	$191.33	$ 31.43	$ 0.50	$ 31.93	$ 223.26	29%	87.88	-	-	-	$ 9.70	(20.69)	-	76.89	97.58
Blundell Geothermal (Dual Flash)	$ 4,277	7.24%	$309.68	$ 110.85	$ 0.50	$ 111.35	$ 421.03	90%	53.40	-	-	$ 5.94		(20.69)	-	38.65	59.34
Greenfield Geothermal (Binary)	$ 6,132	7.24%	$444.03	$ 209.40	$ 0.50	$ 209.90	$ 653.93	90%	82.94	-	-	$ 5.94		(20.69)	-	68.19	88.88
Advance Battery Storage	$ 2,025	8.11%	$164.34	$ 1.00	$ 0.50	$ 1.50	$ 165.84	21%	90.15	539.00	59.29	$ 10.00	$ 7.37	-	16.14	182.95	
Pumped Storage	$ 1,723	7.97%	$137.25	$ 4.30	$ 1.35	$ 5.65	$ 142.90	20%	81.56	539.00	67.38	$ 4.30	$ 8.41	-	18.34	179.99	
Compressed Air Energy Storage (CAES)	$ 1,307	8.11%	$106.02	$ 3.80	$ 1.35	$ 5.15	$ 111.17	47%	27.18	539.00	64.57	$ 5.50	$ 6.97	-	10.10	114.32	
Nuclear (Advance Fission)	$ 5,307	8.09%	$429.48	$ 146.70	$ 6.00	$ 152.70	$ 582.18	85%	78.19	81.14	8.69	$ 1.63	-	-	-	88.50	88.50
Solar (Thin Film PV) - 19% CF	$ 4,191	8.55%	$358.24	$ 59.50	$ 6.00	$ 65.50	$ 423.74	19%	254.59	-	-	-	-	(20.69)	-	233.90	254.59
Solar Concentrating (Thermal Trough, NG backup) - 25% solar	$ 4,033	9.53%	$384.21	$ 120.99	$ 6.00	$ 126.99	$ 511.20	33%	176.84	539.00	14.62	-	$ 1.82	(20.69)	-	172.58	193.27
Solar Concentrating (Thermal Trough) - 30% solar	$ 4,519	7.93%	$358.43	$ 135.56	$ 6.00	$ 141.56	$ 499.99	30%	190.26	-	-	-	$ 1.82	(20.69)	-	171.38	192.07

Table 6.6 – Total Resource Cost for West Side Supply-Side Resource Options, \$19 CO_2 Tax

\$19 CO2 Tax	Capital Cost \$/kW			Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)					
Supply Side Resource Options Mid-Calendar Year 2010 Dollars (\$)				Fixed O&M \$/kW-Yr						Levelized Fuel							
Resource Description	Total Capital Cost	Payment Factor	Annual Payment (\$/kW-Yr)	O&M	Other	Total	Total Fixed (\$/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Tax Credits	Environmental	Total Resource Cost with PTC (Mills/kWh)	Total Resource Cost without PTC (Mills/kWh)
West Side Resource Options																	
Natural Gas (4500 feet)																	
CCCT (Wet "F" 2x1)	\$ 1,067	8.37%	\$89.34	\$ 8.19	\$ 0.50	\$ 8.69	\$ 98.04	56%	19.98	572.00	39.38	\$ 2.98	\$ 4.85	-	5.80	73.01	
CCCT Duct Firing (Wet "F" 2x1)	\$ 538	8.37%	\$45.08	-	\$ 0.50	\$ 0.50	\$ 45.58	16%	32.52	572.00	49.65	\$ 0.55	\$ 6.12	-	7.32	96.16	
CCCT (Wet "G" 1x1)	\$ 1,117	8.37%	\$93.53	\$ 6.75	\$ 0.50	\$ 7.25	\$ 100.78	56%	20.54	572.00	38.62	\$ 4.56	\$ 4.76	-	5.69	74.17	
CCCT Duct Firing (Wet "G" 1x1)	\$ 473	8.37%	\$39.60	-	\$ 0.50	\$ 0.50	\$ 40.10	16%	28.61	572.00	51.60	\$ 0.36	\$ 6.36	-	7.61	94.53	
CCCT Advanced (Wet "H" 1x1)	\$ 1,233	8.37%	\$103.28	\$ 6.75	\$ 0.50	\$ 7.25	\$ 110.53	56%	22.53	572.00	37.76	\$ 4.56	\$ 4.65	-	5.57	75.07	
CCCT Advanced Duct Firing (Wet "H" 1x1)	\$ 605	8.37%	\$50.68	-	\$ 0.50	\$ 0.50	\$ 51.18	16%	36.51	572.00	51.60	\$ 0.36	\$ 6.36	-	7.61	102.44	
Natural Gas (1500 feet)																	
Fuel Cell - Large (solid oxide fuel cell)	\$ 1,593	8.55%	\$136.15	\$ 8.40	\$ 0.50	\$ 8.90	\$ 145.05	95%	17.43	572.00	41.54	\$ 0.03	\$ 5.12	-	6.12	70.24	
SCCT Aero	\$ 909	8.88%	\$80.70	\$ 9.04	\$ 0.50	\$ 9.54	\$ 90.25	21%	49.06	572.00	55.90	\$ 5.12	\$ 6.89	-	8.24	125.21	
Intercooled Aero SCCT	\$ 1,067	8.88%	\$94.77	\$ 6.37	\$ 0.50	\$ 6.87	\$ 101.64	21%	55.25	572.00	53.65	\$ 3.57	\$ 6.61	-	7.91	126.99	
Internal Combustion Engines	\$ 1,046	8.88%	\$92.82	\$ 6.49	\$ 0.50	\$ 6.99	\$ 99.81	21%	54.26	572.00	50.37	\$ 5.50	\$ 6.21	-	7.42	123.76	
SCCT Frame (2 Frame "F")	\$ 901	8.41%	\$75.78	\$ 4.92	\$ 0.50	\$ 5.42	\$ 81.20	21%	44.14	572.00	59.75	\$ 6.51	\$ 7.36	-	8.81	126.57	
Other - Renewables																	
Oregon / Washington Wind (29% CF)	\$ 2,383	8.55%	\$203.69	\$ 31.43	\$ 0.50	\$ 31.93	\$ 235.62	29%	92.75	-	-	-	\$ 9.70	(20.69)	-	81.75	102.45
Greenfield Geothermal (Binary)	\$ 6,132	7.24%	\$444.03	\$ 209.40	\$ 0.50	\$ 209.90	\$ 653.93	90%	82.94	-	-	\$ 5.94	-	(20.69)	-	68.19	88.88
Biomass	\$ 3,509	7.93%	\$278.36	\$ 38.80	\$ 0.50	\$ 39.30	\$ 317.66	91%	39.67	483.58	53.09	\$ 0.96	-	(20.69)	16.11	89.15	109.84
Hydrokinetic (Wave, Buoy) - 21% CF	\$ 5,831	9.53%	\$555.49	\$ 174.92	\$ 6.00	\$ 180.92	\$ 736.41	21%	400.31	-	-	-	-	(20.69)	-	379.61	400.31
Solar (Thin Film PV) - 19% CF	\$ 4,191	8.55%	\$358.24	\$ 56.91	\$ 6.00	\$ 62.91	\$ 421.16	19%	253.04	-	-	-	-	(20.69)	-	232.34	253.04
West Side Resource Options																	
Natural Gas																	
CCCT (Wet "F" 2x1)	\$ 928	8.37%	\$77.69	\$ 7.12	\$ 0.50	\$ 7.62	\$ 85.31	56%	17.39	572.00	39.38	\$ 2.59	\$ 4.85	-	5.80	70.03	
CCCT Duct Firing (Wet "F" 2x1)	\$ 468	8.37%	\$39.20	-	\$ 0.50	\$ 0.50	\$ 39.70	16%	28.32	572.00	49.65	\$ 0.48	\$ 6.12	-	7.32	91.90	

Distributed Generation

Tables 6.7 and 6.8 present the total resource cost attributes for these resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2010 dollars. The resource costs are presented for both the $0 and $19 CO_2 tax levels in recognition of the uncertainty in characterizing emission costs. Additional explanatory notes for the tables are as follows:

- A 14-percent administrative cost (for fixed operation and maintenance) is included in the overall cost of the resources. This cost level is in line with the administration costs of the Utah State Energy Program's Renewable Energy Rebate Program, which was 14 percent of total program costs[39] as well as PacifiCorp's program administrative cost experience.
- Federal tax benefits are included for the following resources based on a percent of capital cost.
    - Reciprocating Engine 10 percent
    - Microturbine 10 percent
    - Fuel Cell 30 percent
    - Gas Turbine 10 percent
    - Industrial Biomass 10 percent
    - Anaerobic Digesters 10 percent
- The resource cost for Industrial Biomass is based on The Cadmus Group data. The fuel is assumed to be provided by the project owner at no cost, a conservative assumption. In reality, the cost to the Company would be each state's filed avoided cost rate; and
- Installation costs for on-site ("micro") solar generation technologies are treated on a total resource cost basis; that is, customer installation costs are included. However, capital costs are adjusted downward to reflect federal benefits of 30 percent of installed system costs. The state tax incentives are not included as the Total Resource Cost test sees the incentive as a benefit to customers who install the systems, but is a cost to the state's tax payers, making the net effect zero.

[39] See the Utah Geological Survey's comments on Rocky Mountain Power's solar incentive program, Docket No. 07-035-T14. The comments can be downloaded at: http://www.psc.state.ut.us/utilities/electric/07docs/07035T14/66677Comments%20from%20State%20of%20Utah%20DNR.pdf

Table 6.7 – Distributed Generation Resource Supply-Side Options

	Location / Timing		Plant Details				Outage Information		Costs			Emissions			
Supply-side Resource Options Mid-Calendar Year 2010 Dollars ($) **Resource Description**	Installation Location	Earliest In-Service Date (Middle of year)	Average Capacity MW	Fuel	Design Plant Life in Years	Annual Average Heat Rate HHV BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate	Base Capital Cost in $/kW	Var. O&M, $/MWh	Fixed O&M in $/kW-yr	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu
Small Combined Heat & Power															
Reciprocating Engine	Utah	2011	0.75	Natural Gas	20	8,000	2%	3%	$ 1,880	-	$ 56.94	0.001	0.101	0.255	118.00
Reciprocating Engine	Oregon / California	2011	0.33	Natural Gas	20	8,000	2%	3%	$ 1,880	-	$ 56.94	0.001	0.101	0.255	118.00
Reciprocating Engine	Washington	2011	0.01	Natural Gas	20	8,000	2%	3%	$ 1,880	-	$ 56.94	0.001	0.101	0.255	118.00
Reciprocating Engine	Wyoming	2011	0.30	Natural Gas	20	8,000	2%	3%	$ 1,880	-	$ 56.94	0.001	0.101	0.255	118.00
Gas Turbine	Not Modeled	2011	0.06	Natural Gas	20	6,300	2%	3%	$ 1,755	-	$ 56.94	0.001	0.050	0.255	118.00
Microturbine	Not Modeled	2011	0.09	Natural Gas	15	8,000	2%	3%	$ 2,595	-	$ 54.02	0.001	0.101	0.255	118.00
Fuel Cell	Not Modeled	2011	0.05	Natural Gas	10	6,300	2%	3%	$ 4,583	-	$ 35.04	0.001	0.003	0.255	118.00
Commercial Biomass, Anaerobic Digester	Not Modeled	2011	0.05	Biomass	20	-	10%	10%	$ 3,293	-	$ 52.97	-	-	-	-
Industrial Biomass, Waste	Utah	2011	3.78	Biomass	15	-	5%	5%	$ 1,752	-	$ 31.54	-	-	-	-
Industrial Biomass, Waste	Oregon / California	2011	3.20	Biomass	15	-	5%	5%	$ 1,752	-	$ 31.54	-	-	-	-
Industrial Biomass, Waste	Idaho	2011	1.22	Biomass	15	-	5%	5%	$ 1,752	-	$ 31.54	-	-	-	-
Industrial Biomass, Waste	Washington	2011	0.99	Biomass	15	-	5%	5%	$ 1,752	-	$ 31.54	-	-	-	-
Industrial Biomass, Waste	Wyoming	2011	1.48	Biomass	15	-	5%	5%	$ 1,752	-	$ 31.54	-	-	-	-
Solar															
Rooftop Photovoltaic	Utah	2011	1.300	Solar	30	-			$ 5,691	-	$ 23.83	-	-	-	-
Rooftop Photovoltaic	Wyoming	2011	0.105	Solar	30	-			$ 5,691	-	$ 23.83	-	-	-	-
Rooftop Photovoltaic	Oregon / California	2011	1.172	Solar	30	-			$ 5,691	-	$ 23.83	-	-	-	-
Rooftop Photovoltaic	Idaho	2011	0.050	Solar	30	-			$ 5,691	-	$ 23.83	-	-	-	-
Rooftop Photovoltaic	Washington	2011	0.172	Solar	30	-			$ 5,691	-	$ 23.83	-	-	-	-
Water Heaters	Utah	2011	2.372	Solar	20	-			$ 1,420	-	$ 11.18	-	-	-	-
Water Heaters	Wyoming	2011	0.466	Solar	20	-			$ 1,420	-	$ 11.18	-	-	-	-
Water Heaters	Oregon / California	2011	0.516	Solar	20	-			$ 1,420	-	$ 11.18	-	-	-	-
Water Heaters	Idaho	2011	0.265	Solar	20	-			$ 1,420	-	$ 11.18	-	-	-	-
Water Heaters	Washington	2011	1.290	Solar	20	-			$ 1,420	-	$ 11.18	-	-	-	-
Attic Fans	Utah	2011	0.35	Solar	10	-			$ 16,939	-	-	-	-	-	-

Table 6.8 – Distributed Generation Total Resource Cost, $0 CO_2 Tax

$0 CO2 Tax	Capital Cost $/kW					Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)			
Supply-side Resource Options Mid-Calendar Year 2010 Dollars ($)						Fixed O&M $/kW-Yr						Levelized Fuel					
Resource Description	Capital Cost	Rebate and Administrative Costs	Net Capital Costs	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Other	Total	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation	Environmental	Total Resource Cost (Mills/kWh)
Small Combined Heat & Power																	
Reciprocating Engine		$ 141.50	$ 1,879.96	11.06%	$ 207.98	$ 56.94	-	$ 56.94	$ 264.92	56%	54.00	539.00	43.12	-	$ 5.36	0.00	$ 102.48
Reciprocating Engine		$ 141.50	$ 1,879.96	11.06%	$ 207.98	$ 56.94	-	$ 56.94	$ 264.92	56%	54.00	572.00	45.76	-	$ 5.64	0.00	$ 105.40
Reciprocating Engine		$ 141.50	$ 1,879.96	11.06%	$ 207.98	$ 56.94	-	$ 56.94	$ 264.92	56%	54.00	572.00	45.76	-	$ 5.64	0.00	$ 105.40
Reciprocating Engine		$ 141.50	$ 1,879.96	11.06%	$ 207.98	$ 56.94	-	$ 56.94	$ 264.92	56%	54.00	539.00	43.12	-	$ 4.66	0.00	$ 101.78
Gas Turbine		$ 132.11	$ 1,755.19	11.06%	$ 194.18	$ 56.94	-	$ 56.94	$ 251.12	95%	30.18	539.00	33.96	-	$ 4.22	0.00	$ 68.35
Microturbine		$ 195.35	$ 2,595.35	11.24%	$ 291.74	$ 54.02	-	$ 54.02	$ 345.76	56%	70.48	539.00	43.12	-	$ 5.36	0.00	$ 118.96
Fuel Cell		$ 344.93	$ 4,582.62	14.79%	$ 677.95	$ 35.04	-	$ 35.04	$ 712.99	95%	85.68	539.00	33.96	-	$ 4.22	0.00	$ 123.85
Commercial Biomass, Anaerobic Digester		$ 247.84	$ 3,292.74	9.53%	$ 313.70	$ 52.97	-	$ 52.97	$ 366.67	80%	52.32	-	-	-		-	$ 52.32
Industrial Biomass, Waste		$ 131.86	$ 1,751.86	11.24%	$ 196.93	$ 31.54	-	$ 31.54	$ 228.46	90%	28.98	-	-	-		-	$ 28.98
Industrial Biomass, Waste		$ 131.86	$ 1,751.86	11.24%	$ 196.93	$ 31.54	-	$ 31.54	$ 228.46	90%	28.98	-	-	-		-	$ 28.98
Industrial Biomass, Waste		$ 131.86	$ 1,751.86	11.24%	$ 196.93	$ 31.54	-	$ 31.54	$ 228.46	90%	28.98	-	-	-		-	$ 28.98
Industrial Biomass, Waste		$ 131.86	$ 1,751.86	11.24%	$ 196.93	$ 31.54	-	$ 31.54	$ 228.46	90%	28.98	-	-	-		-	$ 28.98
Industrial Biomass, Waste		$ 131.86	$ 1,751.86	11.24%	$ 196.93	$ 31.54	-	$ 31.54	$ 228.46	90%	28.98	-	-	-		-	$ 28.98
Solar																	
Rooftop Photovoltaic		$ 325.58	$ 5,691.13	7.93%	$ 451.42	$ 23.83	-	$ 23.83	$ 475.25	17%	311.80	-	-	-		-	$ 311.80
Rooftop Photovoltaic		$ 325.58	$ 5,691.13	7.93%	$ 451.42	$ 23.83	-	$ 23.83	$ 475.25	16%	339.08	-	-	-		-	$ 339.08
Rooftop Photovoltaic		$ 325.58	$ 5,691.13	7.93%	$ 451.42	$ 23.83	-	$ 23.83	$ 475.25	12%	467.70	-	-	-		-	$ 467.70
Rooftop Photovoltaic		$ 325.58	$ 5,691.13	7.93%	$ 451.42	$ 23.83	-	$ 23.83	$ 475.25	15%	354.59	-	-	-		-	$ 354.59
Rooftop Photovoltaic		$ 325.58	$ 5,691.13	7.93%	$ 451.42	$ 23.83	-	$ 23.83	$ 475.25	14%	379.39	-	-	-		-	$ 379.39
Water Heaters		$ 106.88	$ 1,419.92	9.53%	$ 135.28	$ 11.18	-	$ 11.18	$ 146.45	17%	96.08	-	-	-		-	$ 96.08
Water Heaters		$ 106.88	$ 1,419.92	9.53%	$ 135.28	$ 11.18	-	$ 11.18	$ 146.45	16%	104.49	-	-	-		-	$ 104.49
Water Heaters		$ 106.88	$ 1,419.92	9.53%	$ 135.28	$ 11.18	-	$ 11.18	$ 146.45	12%	144.12	-	-	-		-	$ 144.12
Water Heaters		$ 106.88	$ 1,419.92	9.53%	$ 135.28	$ 11.18	-	$ 11.18	$ 146.45	15%	109.27	-	-	-		-	$ 109.27
Water Heaters		$ 106.88	$ 1,419.92	9.53%	$ 135.28	$ 11.18	-	$ 11.18	$ 146.45	14%	116.91	-	-	-		-	$ 116.91
Attic Fans		$ 325.58	$ 16,938.68	14.79%	$ 2,505.91	-	-	-	$ 2,505.91	17%	1,644.04	-	-	-		-	$ 1,644.04

Table 6.8a – Distributed Generation Total Resource Cost, \$19 CO_2 Tax

\$19 CO2 Tax	Capital Cost \$/kW					Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)			
Supply-side Resource Options Mid-Calendar Year 2010 Dollars (\$)						Fixed O&M \$/kW-Yr						Levelized Fuel					
Resource Description	Total Capital Cost	Rebate and Administrative Costs	Net Capital Costs	Payment Factor	Annual Payment (\$/kW-Yr)	O&M	Other	Total	Total Fixed (\$/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Environmental	Total Resource Cost (Mills/kWh)
Small Combined Heat & Power																	
Reciprocating Engine		\$ 141.50	\$ 1,879.96	11.06%	\$ 207.98	\$ 56.94	-	\$ 56.94	\$ 264.92	56%	54.00	550.00	44.00	-	\$ 5.36	6.74	\$ 110.11
Reciprocating Engine		\$ 141.50	\$ 1,879.96	11.06%	\$ 207.98	\$ 56.94	-	\$ 56.94	\$ 264.92	56%	54.00	583.50	46.68	-	\$ 5.64	6.74	\$ 113.07
Reciprocating Engine		\$ 141.50	\$ 1,879.96	11.06%	\$ 207.98	\$ 56.94	-	\$ 56.94	\$ 264.92	56%	54.00	583.50	46.68	-	\$ 5.64	6.74	\$ 113.07
Reciprocating Engine		\$ 141.50	\$ 1,879.96	11.06%	\$ 207.98	\$ 56.94	-	\$ 56.94	\$ 264.92	56%	54.00	550.00	44.00	-	\$ 4.66	6.74	\$ 109.41
Gas Turbine		\$ 132.11	\$ 1,755.19	11.06%	\$ 194.18	\$ 56.94	-	\$ 56.94	\$ 251.12	95%	30.18	550.00	34.65	-	\$ 4.22	5.31	\$ 74.36
Microturbine		\$ 195.35	\$ 2,595.35	11.24%	\$ 291.74	\$ 54.02	-	\$ 54.02	\$ 345.76	56%	70.48	550.00	44.00	-	\$ 5.36	6.74	\$ 126.59
Fuel Cell		\$ 344.93	\$ 4,582.62	14.79%	\$ 677.95	\$ 35.04	-	\$ 35.04	\$ 712.99	95%	85.68	550.00	34.65	-	\$ 4.22	5.31	\$ 129.86
Commercial Biomass, Anaerobic Digester		\$ 247.84	\$ 3,292.74	9.53%	\$ 313.70	\$ 52.97	-	\$ 52.97	\$ 366.67	80%	52.32	-	-	-		-	\$ 52.32
Industrial Biomass, Waste		\$ 131.86	\$ 1,751.86	11.24%	\$ 196.93	\$ 31.54	-	\$ 31.54	\$ 228.46	90%	28.98	-	-	-		-	\$ 28.98
Industrial Biomass, Waste		\$ 131.86	\$ 1,751.86	11.24%	\$ 196.93	\$ 31.54	-	\$ 31.54	\$ 228.46	90%	28.98	-	-	-		-	\$ 28.98
Industrial Biomass, Waste		\$ 131.86	\$ 1,751.86	11.24%	\$ 196.93	\$ 31.54	-	\$ 31.54	\$ 228.46	90%	28.98	-	-	-		-	\$ 28.98
Industrial Biomass, Waste		\$ 131.86	\$ 1,751.86	11.24%	\$ 196.93	\$ 31.54	-	\$ 31.54	\$ 228.46	90%	28.98	-	-	-		-	\$ 28.98
Industrial Biomass, Waste		\$ 131.86	\$ 1,751.86	11.24%	\$ 196.93	\$ 31.54	-	\$ 31.54	\$ 228.46	90%	28.98	-	-	-		-	\$ 28.98
Solar																	
Rooftop Photovoltaic		\$ 325.58	\$ 5,691.13	7.93%	\$ 451.42	\$ 23.83	-	\$ 23.83	\$ 475.25	17%	311.80	-	-	-		-	\$ 311.80
Rooftop Photovoltaic		\$ 325.58	\$ 5,691.13	7.93%	\$ 451.42	\$ 23.83	-	\$ 23.83	\$ 475.25	16%	339.08	-	-	-		-	\$ 339.08
Rooftop Photovoltaic		\$ 325.58	\$ 5,691.13	7.93%	\$ 451.42	\$ 23.83	-	\$ 23.83	\$ 475.25	12%	467.70	-	-	-		-	\$ 467.70
Rooftop Photovoltaic		\$ 325.58	\$ 5,691.13	7.93%	\$ 451.42	\$ 23.83	-	\$ 23.83	\$ 475.25	15%	354.59	-	-	-		-	\$ 354.59
Rooftop Photovoltaic		\$ 325.58	\$ 5,691.13	7.93%	\$ 451.42	\$ 23.83	-	\$ 23.83	\$ 475.25	14%	379.39	-	-	-		-	\$ 379.39
Water Heaters		\$ 106.88	\$ 1,419.92	9.53%	\$ 135.28	\$ 11.18	-	\$ 11.18	\$ 146.45	17%	96.08	-	-	-		-	\$ 96.08
Water Heaters		\$ 106.88	\$ 1,419.92	9.53%	\$ 135.28	\$ 11.18	-	\$ 11.18	\$ 146.45	16%	104.49	-	-	-		-	\$ 104.49
Water Heaters		\$ 106.88	\$ 1,419.92	9.53%	\$ 135.28	\$ 11.18	-	\$ 11.18	\$ 146.45	12%	144.12	-	-	-		-	\$ 144.12
Water Heaters		\$ 106.88	\$ 1,419.92	9.53%	\$ 135.28	\$ 11.18	-	\$ 11.18	\$ 146.45	15%	109.27	-	-	-		-	\$ 109.27
Water Heaters		\$ 106.88	\$ 1,419.92	9.53%	\$ 135.28	\$ 11.18	-	\$ 11.18	\$ 146.45	14%	116.91	-	-	-		-	\$ 116.91
Attic Fans		\$ 325.58	\$ 16,938.68	14.79%	\$ 2,505.91	-	-	-	\$ 2,505.91	17%	1,644.04	-	-	-		-	\$ 1,644.04

Resource Option Description

Coal

Potential coal resources are shown in the supply-side resource options tables as supercritical PC boilers (PC) and IGCC in Utah and Wyoming. Costs for large coal-fired boilers, since the 2007 IRP, have risen by approximately 50 to 60 percent due to many factors involving material shortages, labor shortages, and the risk of fixed price contracting. The recent downturn in the economy has mitigated many of these concerns and prices for coal generation have declined from the previous IRP. Despite these cost decreases the uncertainty of future carbon regulations and difficulty in obtaining construction and environmental permits for coal based generation continues to encourage the Company to postpone the selection of coal as a resource before 2020.

Supercritical technology was chosen over subcritical technology for pulverized coal for a number of reasons. Increasing coal costs are making the added efficiency of the supercritical technology cost-effective for long-term operation. Additionally, there is a greater competitive marketplace for large supercritical boilers than for large subcritical boilers. Increasingly, large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. Due to the increased efficiency of supercritical boilers, overall emission quantities are smaller than for a similarly sized subcritical unit. Compared to subcritical boilers, supercritical boilers can follow loads better, ramp to full load faster, use less water, and require less steel for construction. The smaller steel requirements have also leveled the construction cost estimates for the two coal technologies. The costs for a supercritical PC facility reflect the cost of adding a new unit at an existing site. PacifiCorp does not expect a significant difference in cost for a multiple unit at a new site versus the cost of a single unit addition at an existing site.

CO_2 capture and sequestration technology represents a potential cost for new and existing coal plants if future regulations require it. Research projects are underway to develop more cost-effective methods of capturing carbon dioxide from the flue gas of conventional boilers. The costs included in the supply side resource tables utilize amine based solvent systems for carbon capture. Sequestration would store the CO_2 underground for long-term storage and monitoring.

PacifiCorp and MidAmerican Energy Holdings Company are monitoring CO_2 capture technologies for possible retrofit opportunities at its existing coal-fired fleet, as well as applicability for future coal plants that could serve as cost-effective alternatives to IGCC plants if CO_2 removal becomes necessary in the future. An option to capture CO_2 at an existing coal-fired unit has been included in the supply side resource tables. Currently there are only a couple of large-scale sequestration projects in operation around the world and a number of these are in conjunction with enhanced oil recovery. CCS is not considered a viable option before 2025 due to risk issues associated with technological maturity and underground sequestration liability.

An alternative to supercritical pulverized-coal technology for coal-based generation would be the use of IGCC technology. A significant advantage for IGCC when compared to conventional pulverized coal with amine-based carbon capture is the reduced cost of capturing CO_2 from the process. Gasification plants have been built and demonstrated around the world, primarily as a means of producing chemicals from coal. Only a limited number of IGCC plants have been constructed specifically for power generation. In the U.S., these facilities have been demonstration projects and cost significantly more than conventional coal plants in both capital and operating costs. These projects have been constructed with significant funding from the federal government. A number of IGCC technology suppliers have teamed up with large constructor to form consortia who are now offering to build IGCC plants. A few years ago, these consortia were willing to provide IGCC plants on a lump-sum, turn-key basis. However, in today's market, the willingness of these consortia to design and construct IGCC plants on lump-sum turnkey basis is in question. The costs presented in the supply-side resource options tables reflect recent studies of IGCC costs associated with efforts to partner PacifiCorp with the Wyoming Infrastructure Authority (WIA) to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

PacifiCorp was selected by the WIA to participate in joint project development activities for an IGCC facility in Wyoming. The ultimate goal was to develop a Section 413 project under the 2005 Energy Policy Act. PacifiCorp commissioned and managed feasibility studies with one or more technology suppliers/consortia for an IGCC facility at its Jim Bridger plant with some level of carbon capture. Based on the results of initial feasibility studies, PacifiCorp declined to submit a proposal to the federal agencies involved in the Section 413 solicitation.

PacifiCorp is a member of the Gasification User's Association. In addition, PacifiCorp communicates regularly with the primary gasification technology suppliers, constructors, and other utilities. The results of all these contacts were used to help develop the coal-based generation projects in the supply side resource tables. Over the last two years PacifiCorp has help a series of public meetings as a part of an IGCC Working Group to help provide a broader level of understanding for this technology.

Coal Plant Efficiency Improvements

Fuel efficiency gains for existing coal plants (which are manifested in lower plant heat rates) are realized by (1) emphasizing continuous improvement in operations, and (2) upgrading components if economically justified. Such fuel efficiency improvements can result in a smaller emission footprint for a given level of plant capacity, or the same footprint when plant capacity is increased.

The efficiency of generating units degrades gradually as components wear out over time. During operation, controllable process parameters are adjusted to optimize unit output and efficiency. Typical overhaul work that contributes to improved efficiency includes (1) steam turbine overhauls, (2) cleaning and repairing condensers, feed water heaters, and cooling towers and (3) cleaning boiler heat transfer surfaces.

When economically justified, efficiency improvements are obtained through major component upgrades. Examples include turbine upgrades using new blade and sealing technology, improved seals and heat exchange elements for boiler air heaters, cooling tower fill upgrades, and the addition of cooling tower cells. Such upgrade opportunities are analyzed on a case-by-case basis, and are tied to a unit's major overhaul cycle. PacifiCorp is taking advantage of improved upgrade technology through its "dense pack" coal plant turbine upgrade initiative where justified.

Natural Gas
Natural gas generation options are numerous and a limited number of representative technologies are included in the supply-side resource options table. SCCT and CCCT are included. As with other generation technologies, the cost of natural gas generation has increased substantially from previous IRPs. Costs for gas generation have not decreased since the 2008 IRP, depending on the option, due not only to general utility cost issues mentioned earlier, but also due to the decrease in coal-based projects thereby putting an increased demand on natural gas options that can be more easily permitted.

Combustion turbine options include both simple cycle and combined cycle configurations. The simple cycle options include traditional frame machines as well as aero-derivative combustion turbines. Two aero-derivative machine options were chosen. The General Electric LM6000 machines are flexible, high efficiency machines and can be installed with high temperature SCR systems, which allow them to be located in areas with air emissions concerns. These types of gas turbines are identical to those installed at Gadsby. LM6000 gas turbines have quick-start capability (less than ten minutes to full load) and higher heating value heat rates near 10,000 Btu/kWh. Also selected for the supply-side resource options table is General Electric's new LMS-100 gas turbine. This machine was recently installed for the first time in a commercial venture. It is a cross between a simple-cycle aero-derivative gas turbine and a frame machine with significant amount of compressor intercooling to improve efficiency. The machines have higher heating value heat rates of less than 9,500 Btu/kWh and similar starting capabilities as the LM6000 with significant load following capability (up to 50 MW per minute).

Frame simple cycle machines are represented by the "F" class technology. These machines are about 150 MW at western elevations, and can deliver good simple cycle efficiencies.

Other natural gas-fired generation options include internal combustion engines and fuel cells. Internal combustion engines are represented by a large power plant consisting of 14 machines at 10.9 MW. These machines are spark-ignited and have the advantages of a relatively attractive heat rate, a low emissions profile, and a high level of availability and reliability due to the number of machines. At present, fuel cells hold less promise due to high capital cost, partly attributable to the lack of production capability and continued development. Fuel cells are not ready for large scale deployment and are not considered available as a supply-side option until after 2013.

Combined cycle power plants options have been limited to 1x1 and 2x1 applications of "F" class combustion turbines and a "G" 1x1 facility. The "F" class machine options would allow an expansion of the Lake Side facility. Both the 1x1 and 2x1 configurations are included to give some flexibility to the portfolio planning. Similarly, the "G" machine has been added to take advantage of the improved heat rate available from these more advanced gas turbines. The "G" machine is only presented as a 1x1 option to keep the size of the facility reasonable for selection as a portfolio option. These natural gas technologies are considered mature and installation lead times and capital costs are well known.

Wind

Resource Supply, Location, and Incremental Transmission Costs

PacifiCorp revised its approach for locating wind resources to more closely align with Western Renewable Energy Zones (WREZ), facilitate assignment of incremental transmission costs for the Energy Gateway transmission scenario analysis, and allow the System Optimizer model to more easily select wind resources outside of transmission-constrained areas in Wyoming. Resources are now grouped into a number of wind-generation-only bubbles as well as certain conventional topology bubbles. Wind generation bubbles are intended to enable assignment of incremental transmission costs. Table 6.9 shows the relationship between the topology bubbles and corresponding WREZ.

Table 6.9 – Representation of Wind in the Model Topology

Topology Area	Bubble Type	Topology Bubble Linkage	Corresponding Western Renewable Energy Zone(s)
Wyoming	Wind Generation Only	Linked to *Aeolus*	Wyoming East Central (WY_EC) Wyoming North (WY_NO) Wyoming East (WY_EA) Wyoming South (WY_SO)
Utah	Wind Generation Only	Linked to *Utah South*	Utah West (UT_WE)
Oregon/Washington	Wind Generation Only	Linked to *BPA*	Washington South (WA_SO) Oregon Northeast (OR_NE) Oregon West (OR_WE)
Brady, Idaho	Conventional	N/A	Idaho East (ID_EA)
Walla Walla, WA	Conventional	N/A	Oregon Northeast (OR_NE)
Yakima, WA	Conventional	N/A	Washington South (WA_SO)

Incremental transmission costs are expressed as dollars-per-kW values that are applied to costs of wind resources added in wind-generation-only bubbles.[40] The only exception is for the Oregon/Washington bubble. PacifiCorp's transmission investment analysis indicated that supporting incremental wind additions of over 500 MW in the PacifiCorp west control area would require on the order of $1.5 billion in new transmission facilities (several new 500/230 kV segments would be needed). Since the model cannot automatically apply the transmission cost based on a given megawatt threshold, the incremental transmission cost was removed from this bubble for the base Energy Gateway scenario (which excludes the Wyoming transmission segment) and added as a manual fixed cost adjustment to the portfolio's reported cost if the west side wind additions exceed the 500 MW threshold. *It is important to note that the west-side transmission cost adjustment is only applicable to the Energy Gateway scenario analysis, and not core case portfolio development, which is based on the full Energy Gateway footprint. Only if a core case portfolio included at least 500 MW of west-side wind would PacifiCorp apply an out-of-model transmission cost adjustment. None of the core case portfolios reached this wind capacity threshold.*

[40] Incremental transmission costs also could have been added directly to the wind capital costs. However, assigning a cost to a wind generation bubble avoids the need to individually adjust costs for many wind resources.

In the case of east-side wind resources, the only resource location-dependent transmission cost was $71/kW assigned to Wyoming resources based on an estimated incremental expansion of at least 1,500 MW.

As noted above, the model can also locate wind resources in conventional bubbles. No incremental transmission costs are associated with conventional bubbles, other than wheeling charges where applicable. Transmission interconnection costs—direct and network upgrade costs for connecting a wind facility to PacifiCorp's transmission system (230 kV step-up)—are included in the wind capital costs. It should be noted that primary drivers of wind resource selection are the requirements of renewable portfolio standards and the availability of production tax credits.

Capital Costs

PacifiCorp started with a base set of wind capital costs. The source of these costs is the database of the IPM®, a proprietary modeling system licensed to PacifiCorp by ICF International. These wind capital costs are divided into levels that differentiate costs by site development conditions. PacifiCorp then applied adjustments to the base capital costs to account for federal tax credits, wind integration costs, fixed O&M costs, and wheeling costs as appropriate. (The cost adjustments are converted into discounted values and added to the base capital cost.) These adjusted capital cost values are used only in the System Optimizer model. Table 6.10 shows cost values, WREZ resource potentials, and resource unit limits.

To specify the number of discrete wind resources for a topology bubble, PacifiCorp divided the WREZ resource limit (or depth) by the number of cost levels, rounding to the nearest multiple of 100, and then divided by a 100 MW unit size. (Table 6.10) This formula does not apply to the 200 MW of Washington South and Oregon Northeast wind resources that are available without incremental transmission in the Yakima and Walla Walla bubbles. All wind resources are specified in 100 MW blocks, but the model can choose a fractional amount of a block.

Wind Resource Capacity Factors and Energy Shapes

All resource options in a topology bubble are assigned a single capacity factor. Wyoming resource options are assigned a capacity factor value of 35 percent, while wind resources in other states are assigned a value of 29 percent. Capacity factor is a separate modeled parameter from the capital cost, and is used to scale wind energy shapes used by both the System Optimizer and Planning and Risk (PaR) models. The hourly generation shape reflects average hourly wind variability. The hourly generation shape is repeated for each year of the simulation.

Wind Integration Costs

To capture the costs of integrating wind into the system, PacifiCorp applied a value of $9.70/MWh (in 2010 dollars) for portfolio modeling. The source of this value was the Company's 2010 wind integration study, which is included as Appendix H. Integration costs were incorporated into wind capital costs based on a 25-year project life expectancy and generation performance.

Annual Wind Selection Limits

To reflect realistic system resource addition limits tied to such factors as transmission availability, operational integration, rate impact, resource market availability, and procurement constraints, System Optimizer was constrained to select wind up to certain annual limits. The limit is 200 MW per year with the exception of the hard CO_2 emission cap cases, where the annual limit was specified as 500 MW. These limits apply on a system basis. Note that the effect of the annual limits is to spread wind additions across multiple years rather than cap the cumulative total wind added to a portfolio.

Table 6.10 – Wind Resource Characteristics by Topology Bubble

***Utah South* wind-only bubble**

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Utah	2016	29%	1	3,059	1,516	5
			2	3,508		5
			3	4,180		5

***BPA* wind-only bubble**

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Washington South (Yakima)	2016	29%	1	3,454	2,566	9
			2	3,927		9
			3	4,633		9
Oregon Northeast (Walla Walla)	2016	29%	1	3,597	1,464	5
			2	4,074		5
			3	4,788		5
Oregon West	2016	29%	1	3,597	196	1
			2	4,074		1
			3	4,788		1

Wyoming wind resources in *Aeolus* wind-only bubble

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Wyoming South	2018	35%	1	3,147	1,324	13
Wyoming North	2018	35%	1	3,147	3,063	31
Wyoming East Central	2018	35%	1	3,147	2,594	26
Wyoming East	2018	35%	1	3,147	7,257	73

Idaho (Goshen) wind resources in *Brady* bubble

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Idaho East	2016	29%	1	3,339	618	2
			2	3,788		2
			3	4,460		2

Oregon/Washington wind resources that do not require new incremental transmission *

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Washington South (Yakima)	2013	29%	1	2,393	n/a	1
Oregon Northeast (Walla Walla)	2013	29%	1	2,393	n/a	1

* This section includes only the 200 MW of Oregon and Washington wind resources that do not require incremental transmission. Wind resources in these areas that require additional transmission are modeled with the parameters shown in the "*BPA* wind only bubble" section above.

Other Renewable Resources

Other renewable generation resources included in the supply-side resource options table include geothermal, biomass, landfill gas, waste heat and solar. The financial attributes of these renewable options are based on EPRI's TAG® database and have been adjusted based on PacifiCorp's recent construction and study experience.[41]

Geothermal

In response to the 2008 IRP Update, comments from the Utah stakeholders requested a geothermal resources study to review the geothermal resources in PacifiCorp's service territory. A geothermal resources study was commissioned by PacifiCorp in 2010 and performed by Black & Veatch in conjunction with GeothermEx. The study established criteria for the commercial viability for a geothermal resource as a resource with at least 25 percent of the geothermal resource capacity drilled and operated in the past. While over 80 potential projects were identified within 100 miles of an interconnection to the PacifiCorp grid only eight resources met the commercial criteria. Figure 6.2 and Table 6.11, which come from the report, identify the eight resources and compares their capacity and cost attributes, including the levelized cost of energy (LCOE).[42] All resources, except Roosevelt hot springs (Blundell) because of moderate fluid temperatures, would use binary technology and are inherently more costly and less efficient than the flash design suitable for the higher temperature brine at Blundell. For the supply side table, two types of geothermal resources are defined. East side geothermal refers to the Roosevelt Hot Springs resource (Blundell) and utilizes a cost estimate equivalent to the study conclusion and the current expectation for the cost of a third unit at the Blundell plant. Other geothermal resources are designated Greenfield geothermal and utilize a cost equal to the average of the binary geothermal costs from the geothermal study. These additional geothermal resources are considered western resources for modeling purposes.

PacifiCorp has committed to conduct additional geothermal studies in 2011 to further define and quantify the geothermal opportunities uncovered in the 2010 geothermal study. The 2011 study will also look and the other identified geothermal options and determine which, if any, merits additional development work. The 2011 study will identify new geothermal opportunities sufficient to allow a request for approval of development funds for recovery from the various state commissions.

[41] Technical Assessment Guide, Electric Power Research Institute, Palo Alto, CA.

[42] The levelized cost of energy is the constant dollar cost of the energy generated over the life of the project, and includes operation and maintenance costs, investment costs, and taxes/tax benefits.

Figure 6.2 – Commercially Viable Geothermal Resources Near PacifiCorp's Service Territory

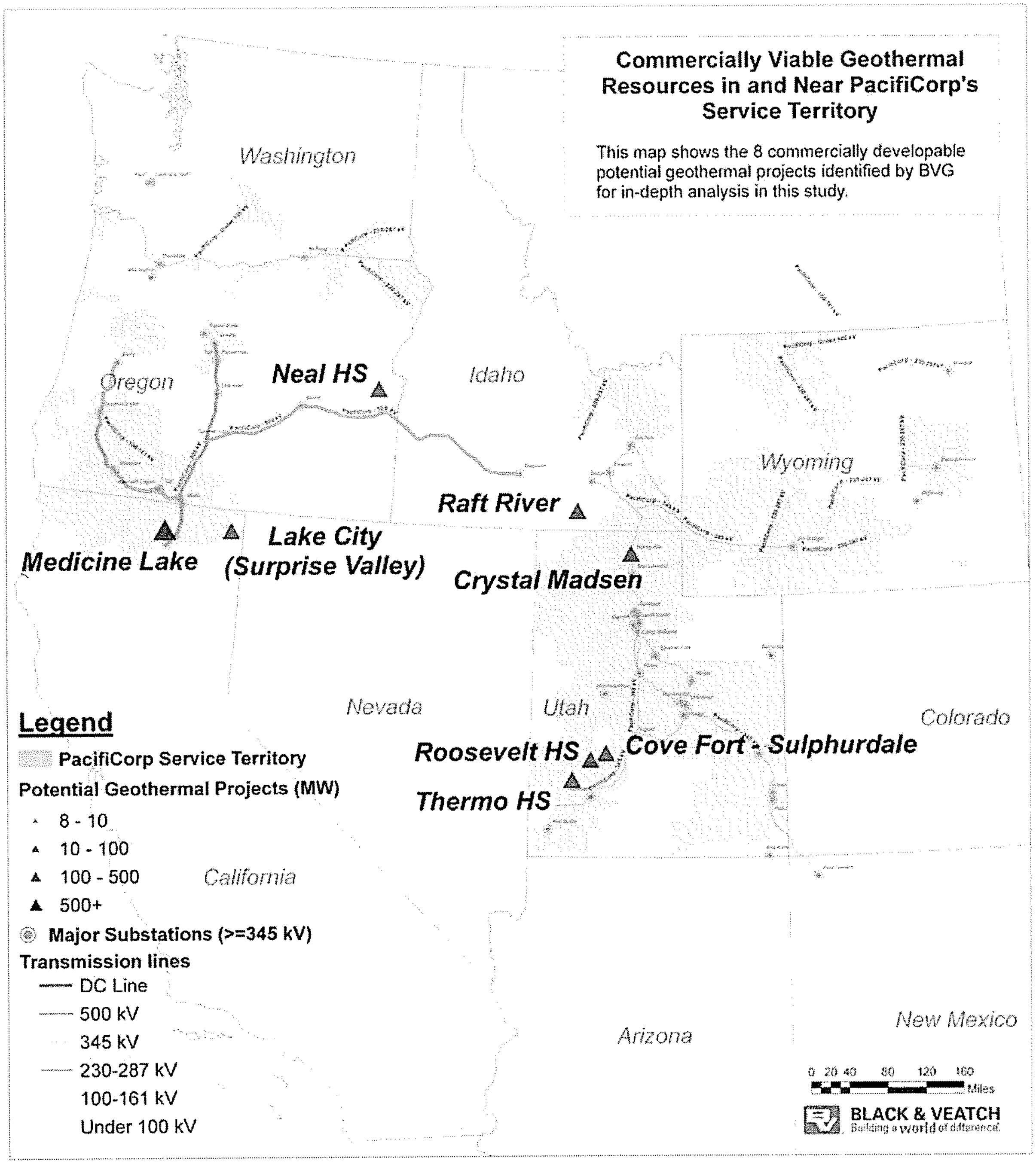


Table 6.11 – 2010 Geothermal Study Results

Table 1-1. Sites Selected for In-Depth Review.

Field Name	State	Additional Capacity Available (Gross MW)	Additional Capacity Available (Net MW)	Additional Capacity Available to PacifiCorp (Net MW)[a]	Anticipated Plant Type for Additonal Capacity	LCOE (Low, $/MWh)[b,c]	LCOE (High, $/MWh)[b,c]
Lake City	CA	30	24	24	Binary	$83	$90
Medicine Lake	CA	480	384	384	Binary	$91	$98
Raft River	ID	90	72	43	Binary	$93	$100
Neal Hot Springs	OR	30	24	0	Binary	$80	$87
Cove Fort	UT	100	80	60 to 63	Binary	$68	$75
Crystal-Madsen	UT	30	24	0	Binary	$93	$100
Roosevelt Hot Springs	UT	90	81[d]	81[d]	Flash/Binary Hybrid	$46	$51
Thermo Hot Springs	UT	118	94	0	Binary	$91	$98
Totals		***968***	***783***	***592 to 595***			

Source: BVG analysis for PacifiCorp.
Note:
[a] Calculated by subtracting the amount of resource under contract to or in contract negotiations with other parties from the estimated net capacity available.
[b] Net basis
[c] These screening level cost estimates are based on available public information. More detailed estimates based on proprietary information and calculated on a consistent basis might yield different comparisons.
[d] While 81 MW net are estimated to be available, the resource should be developed in smaller increments to verify resource sustainability

Biomass

The biomass project option would involve the combustion of whole trees grown in a plantation setting, presumably in the Pacific Northwest.

Solar

Three solar resources were defined. A concentrating PV system represents a utility scale PV resource. Optimistic performance and cost figures were used equivalent to the best reported PV efficiencies. Solar thermal projects are represented by both a solar concentrating design trough system with natural gas backup and a solar concentrating design thermal tower arrangement with six hours of thermal storage. The system parameters for these systems were suggested by the WorleyParsons Group study and reflect current proposed projects in the desert southwest. Efforts are being undertaken in 2011 to verify this data. A two-megawatt solar project will be built in Oregon as a part of the Oregon solar initiative. Development of PV resources in Utah will be studied with Sandia National Laboratories.

Combined Heat and Power and Other Distributed Generation Alternatives

Combined heat and power (CHP) plants are small (ten megawatts or less) gas compressor heat recovery systems using a binary cycle. PacifiCorp evaluated both larger systems that would be contracted at the customer site (labeled as utility cogeneration in Tables 6.1, 6.3, and 6.5) and smaller distributed generation systems.

A large CHP (40 to 120 megawatts) combustion turbine with significant steam based heat recovery from the flue gas has not been included in PacifiCorp's supply-side table for the eastern service territory due to a lack of large potential industrial applications. These CHP opportunities are site-specific, and the generic options presented in the supply-side resource options table are not intended to represent any particular project or opportunity.

Small distributed generation resources are unique in that they reside at the customer load. The generation can either be used to reduce the customer load, such as net metering, or sold to the utility. Small CHP resources generate electricity and utilize waste heat for space and water heating requirements. Fuel is either natural gas or renewable biogas. On-site solar resources, also referred to as "micro solar", include electric generation and energy-efficiency measures that use solar energy. The DG resources are up to 4.8 MW in size.

Table 6.12 shows modeling attributes for the distributed generation resources reflected in The Cadmus Group's 2010 potentials study. Rather than using the year-by-year resource potentials for 2011-2030 from The Cadmus Group, PacifiCorp calculated the average annual values based on the 2030 cumulative resource totals.[43] PacifiCorp also applied a three-megawatt threshold for the average annual capacity values to designate resources to include in the IRP models.

Table 6.12 – Distributed Generation Resource Attributes

Technology Type	Available MW Capacity each Year by Topology Bubble 1/						Annual Fixed O&M Costs ($/kW)	Measure Life (Yrs)	Heat Rate (Ave. Btu/kWh)	Admin Cost (% of total program cost)	Capital Cost ($/kW), Total Resource Cost basis	Technology Cost Change
	South/Central Oregon plus California	Walla Walla, WA	Yakima, WA	Goshen, ID	Utah North	Wyoming Southwest						
Reciprocating Engine	0.33	0.01	-	-	0.75	0.30	56.94	20	8,000	14%	1,880	1%
MicroTurbine	-	-	-	-	-	-	54.02	15	8,000	14%	2,595	-1%
Fuel Cell	-	-	-	-	-	-	35.04	10	6,300	14%	4,583	-3%
Gas Turbine	-	-	-	-	-	-	56.94	20	6,300	14%	1,755	1%
Industrial Biomass	3.20	0.36	0.63	1.22	3.78	1.48	31.54	15	N/A	14%	1,752	1%
Anaerobic Digesters	-	-	-	-	-	-	52.97	20	N/A	14%	3,293	-1%
PV	1.17	0.08	0.09	0.05	1.30	0.11	23.83	30	N/A	14%	5,691	-2%
Solar Water Heaters	0.52	0.32	0.97	0.27	2.37	0.47	11.18	20	N/A	14%	1,420	2%
Solar Attic Fans	-	-	-	-	0.35	-	0.00	10	N/A	14%	16,939	2%

1/ Technologies with no capacities listed indicate that the average annual capacity for 2011-2030 is less than the 3 MW threshold for inclusion in the IRP models.

Introduction of many new distributed generation technologies designed to fill the needs of niche markets has helped spur reductions in capital and operating costs.

More details on the distributed generation resources can be found in the Cadmus potentials study report available for download on PacifiCorp's demand-side management Web page, http://www.pacificorp.com/es/dsm.html.

[43] Many of the annual capacity potentials are a small fraction of a megawatt. This resource set-up approach enabled one resource with multiple units to be defined for each technology as opposed to an individual resource having to be defined for each year. The number of resource options is one of the key factors that establish model run-time.

As in past IRPs, a number of energy storage technologies are included, such as compressed energy storage (CAES), pumped hydroelectric, and advanced batteries. There are a number of potential CAES sites—specifically solution-mined sites associated with gas storage in southwest Wyoming—that could be developed in areas of existing gas transmission. CAES may be an attractive alternative for high elevation sites since the gas compression could compensate for the higher elevation. Thermal energy storage is also included as a load control (Class 1 DSM) resource. Although not included in this IRP, flywheel energy storage systems show promise for such applications as frequency regulation, and will be investigated for the next IRP as PacifiCorp gathers data from other utility test projects and assesses resource potential for its own system.

Nuclear
An emissions-free nuclear plant has been included in the supply-side resource options table. This option is based recent internal studies, press reports and information from a paper prepared by the Uranium Information Centre Ltd., "The Economics of Nuclear Power," May 2008. A 1,600 MW plant is characterized utilizing advanced nuclear plant designs with an assumed location in Idaho. Modeled capital costs include incremental transmission costs to deliver energy into PacifiCorp's system. Nuclear power is not considered a viable option in the PacifiCorp service territory before 2030.

Demand-side Resources

Resource Options and Attributes

Source of Demand-side Management Resource Data
DSM resource opportunity estimates used in the development of the 2011 IRP were derived from an update to the "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" study completed in June 2007 (DSM potential study). The 2010 DSM potential study, conducted by The Cadmus Group, provided a broad estimate of the size, type, location and cost of demand-side resources.[44] The demand-side resource information was converted into supply-curves by type of DSM; e.g. capacity-based Classes 1 and 3 DSM and energy-based Class 2 DSM for modeling against competing supply-side alternatives.

Demand-side Management Supply Curves
Resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and costs of resources. Supply curves incorporate a linear relationship between quantities and costs (at least up to the maximum quantity available) to help identify at any particular cost how much of a particular resource can be acquired. Resource modeling utilizing supply curves allows utilities to sort out and select the least-cost resources (products and quantities) based on each resource's cost versus quantity in comparison to the supply curves of alternative and competing resource types.

[44] The Cadmus DSM potentials report is available on PacifiCorp's demand-side management Web page. http://www.pacificorp.com/es/dsm.html.

As with supply-side resources, the development of demand-side resource supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to demand-side supply curves include:

- resource quantities available in year one—either megawatts or megawatt-hours—recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year
- resource quantities available over time; for example, Class 2 DSM energy-based resource measure lives
- seasonal availability and hours available (Classes 1 and 3 DSM capacity resources)
- the shape or hourly contribution of the resource (load shape of the Class 2 DSM energy resource); and
- levelized resource costs (dollars per megawatt per year for Classes 1 and 3 DSM capacity resources, or dollars per megawatt-hour for Class 2 DSM energy resources).

Once developed, DSM supply curves are treated like any other discrete supply-side resource in the IRP modeling environment. A complicating factor for modeling is that the DSM supply curves must be configured to meet the input specifications for two models: the System Optimizer capacity expansion optimization model, and the Planning and Risk production cost simulation model.

Class 1 DSM Capacity Supply Curves
Supply curves were created for five discrete Class 1 DSM products:

1) residential air conditioning
2) residential electric water heating
3) irrigation load curtailment
4) commercial/industrial curtailment; and
5) commercial/industrial thermal energy storage

The potentials and costs for each product were provided at the state level resulting in five products across six states, or thirty supply curves before accounting for system load areas (some states cover more than one load area). After accounting for load areas, a total of fifty Class 1 DSM supply curves were used in the 2011 IRP modeling process.

Class 1 DSM resource price differences between west and east control areas for similar resources were driven by resource differences in each market, such as irrigation pump size and hours of operation as well as product performance differences. For instance, residential air conditioning load control in the west is more expensive on a unitized or dollar per kilowatt-year basis due to climatic differences that result in less contribution or load available per installed switch.

The combination residential air conditioning and electric water heating dispatchable load control product was not provided to the System Optimizer model as a resource option for either control area. In the west, electric water heating control wasn't included as it adds little additional load for the cost, and electric water heating market share continues to decline each year as a result of conversions to gas. In the east, electric water heating control wasn't included because (1) the market potential is very small. (It is predominantly a gas water heating market), (2) an established program already exists that doesn't include a water heater control component, and (3) the potential identified is assumed to be located in areas where gas is not available; such as more rural and mountainous areas where direct load control paging signals are less reliable.

The assessment of potential for distributed standby generation was combined with an assessment of commercial/industrial energy management system controls in the development of the resource opportunity and costs of the commercial/industrial curtailment product. The costs for this product are constant across all jurisdictions under the pay-for-performance delivery model assumed.

Tables 6.13 and 6.14 show the summary level Class 1 DSM program information, by control area, used in the development of the Class 1 resources supply curves. As previously noted, the products were further broken down by quantity available by state and load area in order to provide the model with location-specific details.

Table 6.13 – Class 1 DSM Program Attributes West Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)	Year Available
Residential and Small Commercial Air Conditioning	Yes, with residential time-of-use	50 hours, not to exceed 6 hours per day	Summer	14	$116-159	2013
Residential Electric Water Heating	Yes, with residential time-of-use	50 hours	Summer	5	$88	2013
Irrigation Direct Load Control	Yes, with irrigation time-of-use	50 hours, not to exceed 6 hours per day	Summer	27	$74	2013
Commercial/Industrial Curtailment (includes distributed stand-by generation)	Yes, with Thermal Energy Storage, demand buyback, and commercial Class 3 time related price products	80 hours, not to exceed 6 hours per day	Summer and Winter	40	$82	2013
Commercial/industrial Thermal Energy Storage	Yes, with commercial Class 3 time related price products	480 hours	Summer	1	$253	2013

Table 6.14 – Class 1 DSM Program Attributes East Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)	Year Available
Residential and Small Commercial Air Conditioning	Yes, with residential time-of-use	50 hours, not to exceed 6 hours per day	Summer	89	$116	2012
Residential Electric Water Heating	Yes, with residential time-of-use	50 hours	Summer	5	$88	2013
Irrigation Direct Load Control	Yes, with irrigation time-of-use	50 hours, not to exceed 6 hours per day	Summer	28	$50-$74	2012
Commercial/Industrial Curtailment (includes distributed stand-by generation)	Yes, with Thermal Energy Storage, demand buyback, and commercial Class 3 time related price products	80 hours, not to exceed 6 hours per day	Summer and Winter	95	$82	2012
Commercial/industrial Thermal Energy Storage	Yes, with commercial Class 3 time related price products	480 hours	Summer	6	$253	2013

To configure the supply curves for use in the System Optimizer model, there are a number of data conversions and resource attributes that are required by the System Optimizer model. All programs are defined to operate within a 5x8 hourly window and are priced in $/kW-month. The following are the primary model attributes required by the model:

- **The Capacity Planning Factor (CPF):** This is the percentage of the program size (capacity) that is expected to be available at the time of system peak. For Classes 1 and 3 DSM programs, this parameter is set to 1 (100 percent)
- **Additional reserves:** This parameter indicates whether additional reserves are required for the resource. Firm resources, such as dispatchable load control, do not require additional reserves.
- **Daily and annual energy limits:** These parameters, expressed in Gigawatt-hours, are used to implement hourly limits on the programs. They are obtained by multiplying the hours available by the program size.
- **Nameplate capacity (MW) and service life (years)**

- **Maximum Annual Units:** This parameter, specified as a pointer to a vector of values, indicates the maximum number of resource units available in the year for which the resource is designated.
- **First year and month available / last year available**
- **Fractional Units First Year:** For resources that are specified such that the model can select fractions of megawatts, this parameter tells the model the first year in which a fractional quantity of the resource can be selected. Year 2011 is entered in order to make these DSM resource options available in all years.

After the model has selected DSM resources, a program converts the resource attributes and quantities into a data format suitable for direct import into the Planning and Risk model.

Class 3 DSM Capacity Supply Curves

Supply curves were created for five discrete Class 3 DSM products, which are capacity-based resources like Class 1 DSM products:

1) residential time-of-use rates;
2) commercial critical peak pricing;
3) commercial and industrial demand buyback;
4) commercial and industrial real-time pricing; and
5) mandatory Irrigation time-of-use[45]

The potentials and costs for each product were provided at the state level resulting in five products across six states, or thirty supply curves before accounting for system load areas (some states cover more than one load area). After accounting for load areas, a total of fifty Class 3 DSM supply curves were used in the 2011 IRP modeling process.

In providing the data for the construction of Class 3 DSM supply curves, the Company did not net out one product's resource potential against a competing product. As Class 3 DSM resource selections are not included as base resources for planning purposes, not taking product interactions into consideration poised no risk of over-reliance (or double counting the potential) of these resources in the final resource plan. For instance, in the development of the supply curves for residential time-of-use the program's market potential was not adjusted by the market potential or quantity available of a lesser-cost alternative, residential critical peak pricing.

Market potentials and costs for each of the five Class 3 DSM programs modeled were taken from the estimates provided in the Updated DSM potential study and evaluated independently as if it were the only resource available targeting a particular customer segment.

Modest product price differences between west and east control areas were driven by resource opportunity differences. The DSM potential study assumed the same fixed costs in each state in

[45] This rate design is an alternative product to the voluntary Class 1 irrigation load management product and assumes regulators and interested parties would support mandatory participation with sufficiently high rates to enable realization of peak energy reduction potential.

which it is offered regardless of quantify available. Therefore, states with lower resource availability for a particular product have a higher cost per kilowatt-year for that product.

Tables 6.15 and 6.16 show the summary level Class 3 DSM program information, by control area, used in the development of the Class 3 DSM resources supply curves. As previously noted, the products were further broken down by quantity available by state and load bubble in order to provide the model with location specific information.

Table 6.15 – Class 3 DSM Program Attributes West Control area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)	Year Available
Residential Time-of-Use	Yes, with Res A/C and water heater DLC	480/600 hours	Summer and Winter	7	$13	2013
Commercial Critical Peak Pricing	Yes, with C&I curtailment, demand buyback and other Class 3 time related price products	40 hours	Summer	17	$13	2013
Commercial/Industrial Demand Buyback	Yes, with C&I curtailment and Class 3 time related price products	87 hours	Summer and Winter	6	$18	2011
Commercial/Industrial Real Time Pricing	Yes, with C&I curtailment, demand buyback and other Class 3 time related price products	87 hours	Summer and Winter	2	$8	2013
Mandatory Irrigation Time-of-Use	Yes, with irrigation DLC	480 hours	Summer	125	$9	2013

Table 6.16 – Class 3 DSM Program Attributes East Control area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)	Year Available
Residential Time-of-Use	Yes, with Res A/C and Water Heater DLC	480/600 hours	Summer and Winter	12	$13	2013
Commercial Critical Peak Pricing	Yes, with C&I curtailment, demand buyback and other Class 3 time related price products	40 hours	Summer	100	$13	2013
Commercial/Industrial Demand Buyback	Yes, with C&I curtailment and Class 3 time related price products	87 hours	Summer and Winter	40	$18	2013

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)	Year Available
Commercial/Industrial Real Time Pricing	Yes, with C&I curtailment, demand buyback and other Class 3 time related price products	87 hours	Summer and Winter	23	$6	2013
Mandatory Irrigation Time-of-Use	Yes, with irrigation DLC	480 hours	Summer	182	$4-9	2013

System Optimizer data formats and parameters for Class 3 DSM programs are similar to those defined for the Class 1 DSM programs. The data export program converts the Class 3 DSM programs selected by the model into a data format for import into the Planning and Risk model.

Class 2 DSM, Capacity Supply Curves

The 2011 IRP represents the second time the Company has utilized the supply curve methodology in the evaluation and selection of Class 2 DSM energy products. The Updated DSM potential study provided the information to fully assess the contribution of Class 2 DSM resources over the IRP planning horizon and adjusted resource potentials and costs taking into consideration changes in codes and standards, emerging technologies, resource cost changes, and state specific modeling conventions and resource evaluation considerations (Washington and Utah). Class 2 DSM resource data was provided by state down to the individual measure and facility levels; e.g., specific appliances, motors, air compressors for residential buildings, small offices, etc. When compared to the 2007 DSM potential study, the number of measures in the Updated DSM potential study increased, primarily due to utilizing the relevant measure level data developed in support of the Northwest Power and Conservation Council's 6th Power Plan. In all, the Updated DSM potential study provided Class 2 DSM resource information at the following granularity level:

- **State:** Washington, California, Idaho, Utah, Wyoming
- **Measure:**
  - 126 residential measures
  - 133 commercial measures
  - 67 industrial measures
  - Three irrigation measures
  - 12 street lighting measures
- **Facility type[46]:**
  - Six residential facility types
  - 24 commercial facility types
  - 14 industrial facility types
  - One irrigation facility type
  - One street lighting type

[46] Facility type includes such attributes as existing or new construction, single or multi-family, etc. Facility types are more fully described in the Updated DSM potential study.

The DSM potential study also provided total resource costs, which included both measure cost and a 15 percent adder for administrative costs levelized over measure life at PacifiCorp's cost of capital, consistent with the treatment of supply-side resource costs. Utah resource costs were levelized using utility costs instead of total costs and an adder for administration.

The technical potential for all Class 2 DSM resources across five states over the twenty-year DSM potential study horizon totaled 12.3 million MWh. The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (achievable). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 10.1 million MWh.

Despite the granularity of Class 2 DSM resource information available, it was impractical to use this much information in the development of Class 2 DSM resource supply curves. The combination of measures by facility type and state generated over 18,000 separate permutations or distinct measures that could be modeled using the supply curve methodology.[47] This many supply curves is impossible to handle with PacifiCorp's IRP models. To reduce the resource options for consideration, while not losing the overall resource quantity available, the decision was made to consolidate like measures into bundles using levelized costs to reduce the number of combinations to a more manageable number. The result was the creation of nine cost bundles; three more cost bundles than were developed for the 2008 IRP.

The bundles were developed based on the Class 2 DSM Update potential study's technical potentials. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure type was adjusted to reflect the achievable acquisitions over the 20 year planning horizon. Consistent with regional planning assumptions in the Northwest, 85 percent of the technical potential for discretionary (retrofit) resources was assumed to be achievable over the twenty year planning period. For lost-opportunity (new construction or equipment failure) the achievable potential is 65 percent of the technical over the twenty year planning period. This assumption is also consistent with planning assumptions in the Pacific Northwest. During the planning period, the aggregate (both discretionary and lost opportunity) achievable potential is 82 percent of the technical potential.

The application of ramp rates in the current Class 2 DSM is a change from the 2007 DSM Potential Study in which the technical achievable potential was assumed to be equally available in increments that were 1/20[th] of the total. In the updated DSM Potential Study, the technical achievable potential for each measure by state is assigned a ramp rate that reflects the relative state of technology and state programs. New technologies and states with newer programs were

[47] Not all energy efficiency measures analyzed are applicable to all market segments. The two most common reasons for this are (1) differences in existing and new construction and (2) some end-uses do not exist in all building types. For example, a measure may look at the savings associated with increasing an existing home's insulation up to current code levels. However, this level of insulation would already be required in new construction, and thus, would not be analyzed for the new construction segment. Similarly, certain measures, such as those affecting commercial refrigeration would not be applicable to all commercial building types, depending on the building's primary business function; for example, office buildings would not typically have commercial refrigeration.

assumed to take more time to ramp up than states and technologies with more extensive track records. Use of ramp rate assumptions is also consistent with regional planning assumptions in the Northwest.

Nine cost bundles across five states (excluding Oregon), and over twenty years, equates to 900 supply curves before allocating across the Company load areas shown in Table 6.17. In addition, there are compact florescent lamp (CFL) bundles for 2011 and 2012, which are discussed later in this section.

Table 6.17 – Load Area Energy Distribution by State

State	Goshen, ID	Utah	Walla Walla, Washington	South/Central Oregon and California	Wyoming	Yakima, Washington
CA				100%		
OR			4%	96%		
ID	42%	58%				
UT		100%				
WA			25%			75%
WY		18%			82%	

After the load areas are accounted for (with some states served in more than one load area as noted in table 6.17), the number of supply curves grew to 1,440, excluding Oregon.

Figures 6.3 through 6.9 show the changes in Class 2 DSM resource potential (adjusted for achievable acquisitions) by state relative to the last update conducted in 2009.

Figure 6.3 – PacifiCorp Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

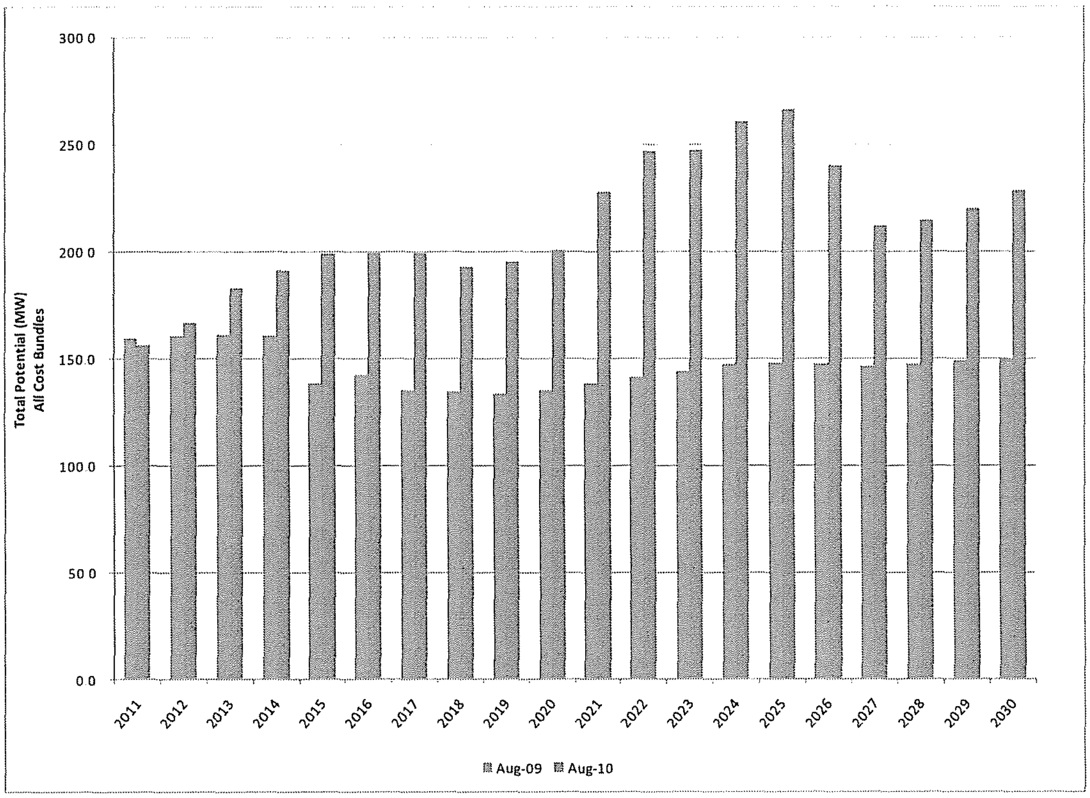


Figure 6.4 – California Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

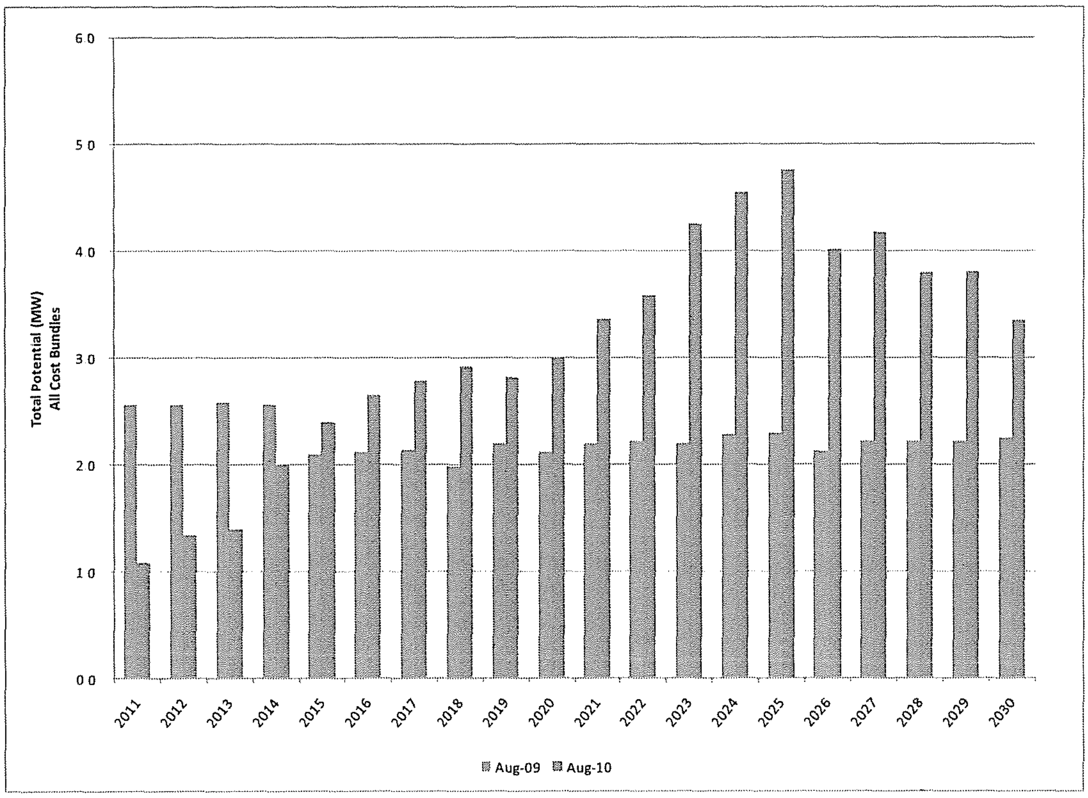


Figure 6.5 – Oregon Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

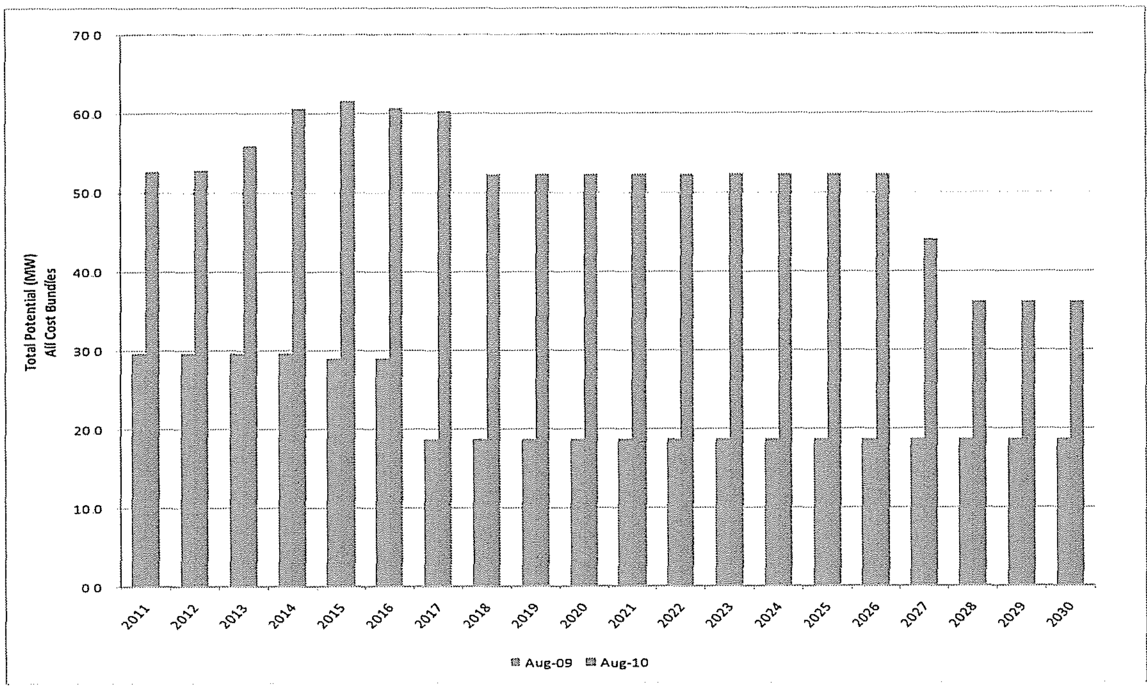


Figure 6.6 – Washington Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

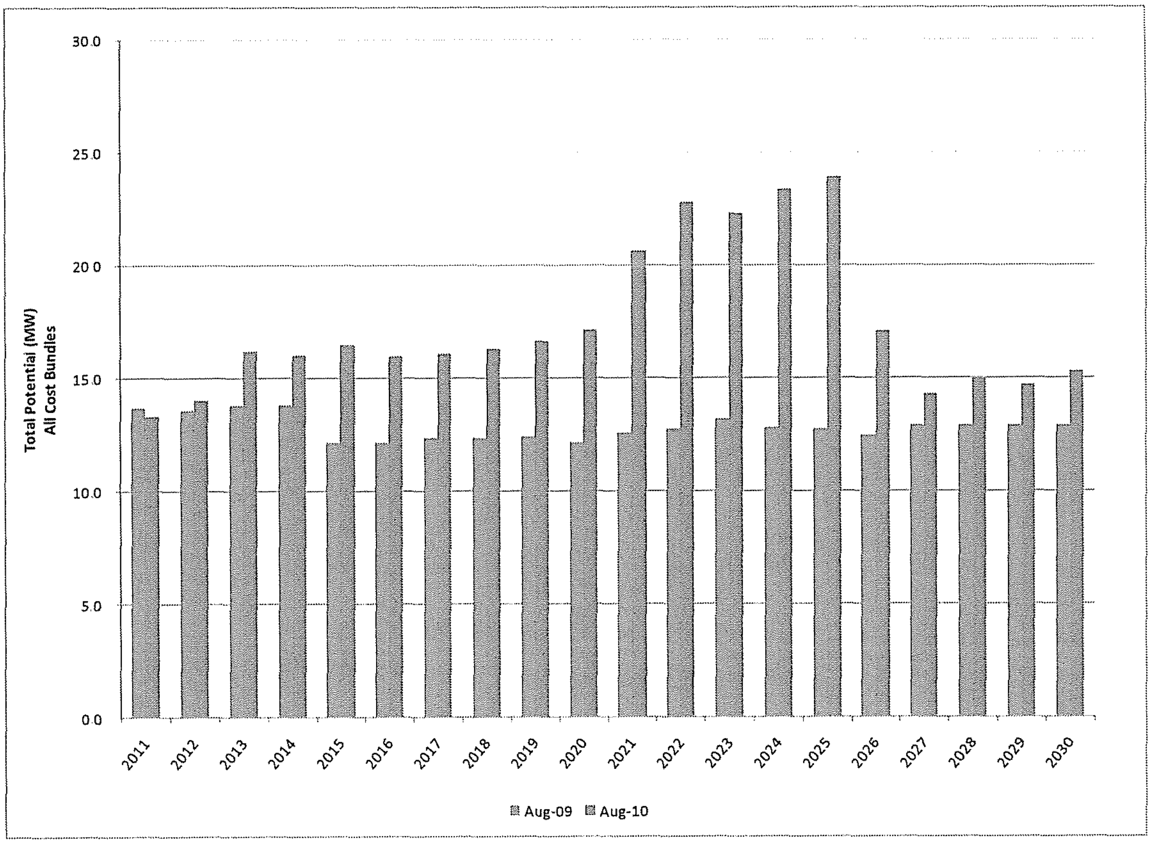


Figure 6.7 – Utah Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

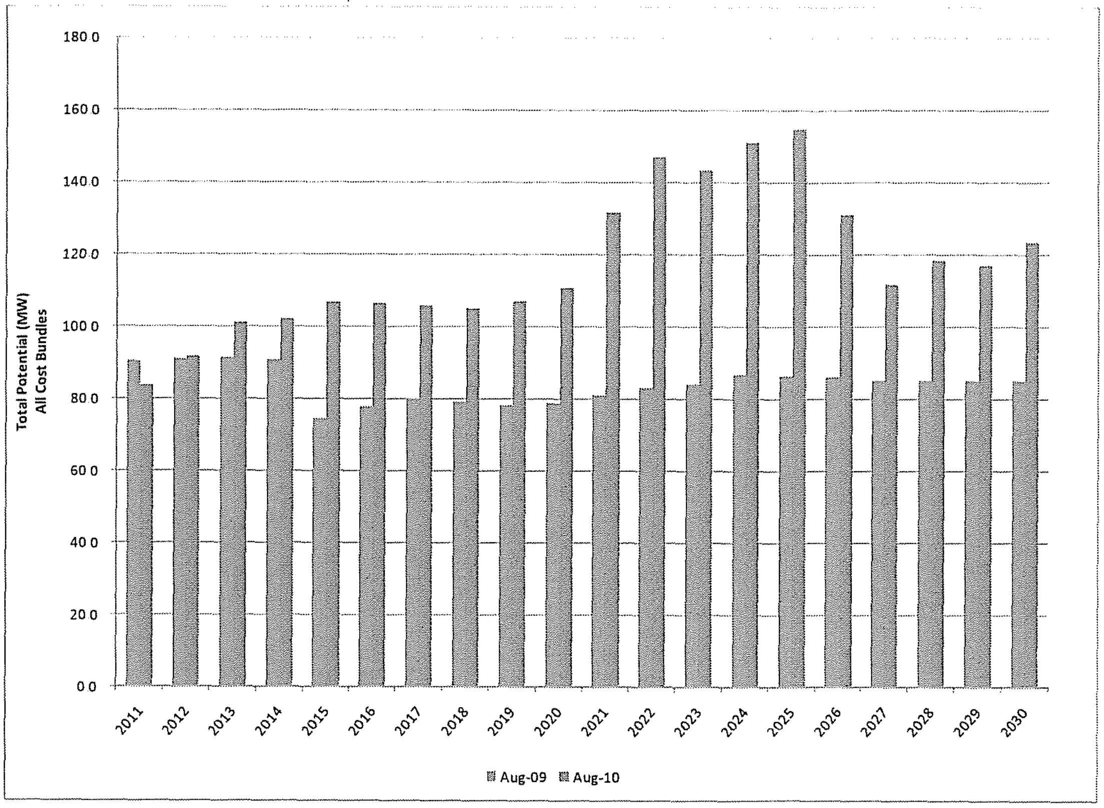


Figure 6.8 – Idaho Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

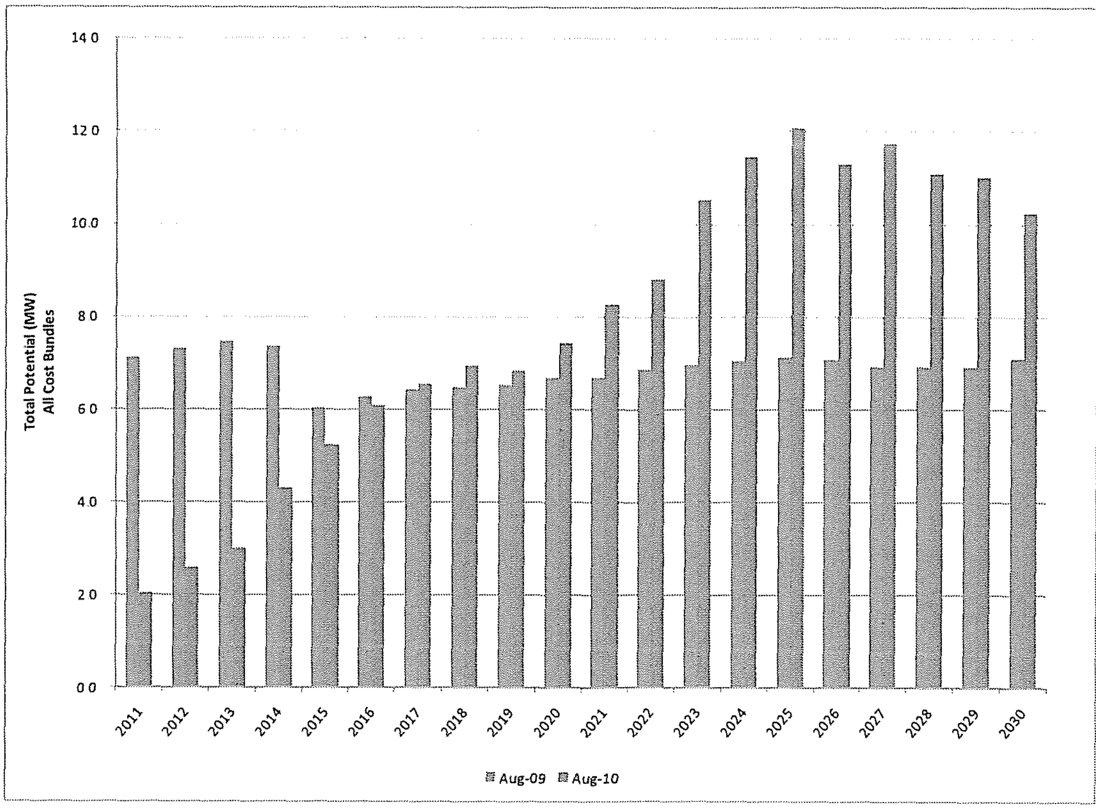


Figure 6.9 – Wyoming Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

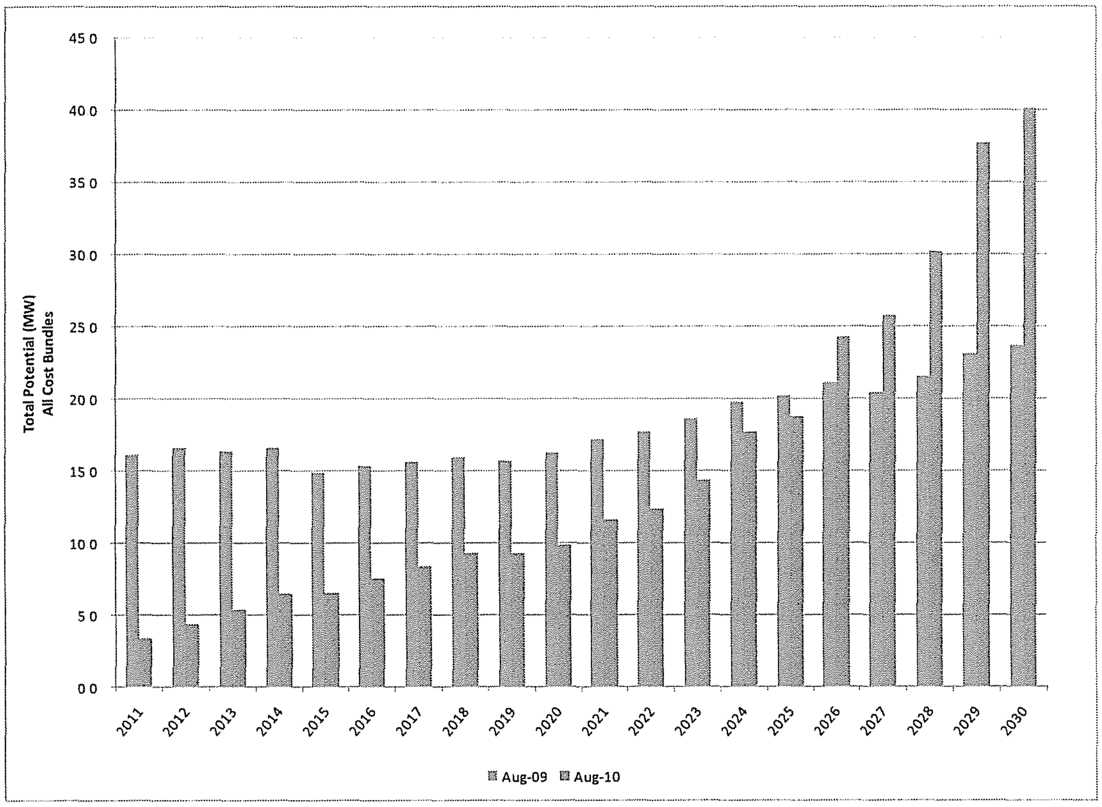


Figure 6.10 shows the Class 2 DSM cost bundles, designated by $/kWh cost breakpoints (e.g., $0.00/kWh to $0.07/kWh) and the associated bundle price after applying cost credits. These cost credits include the following:

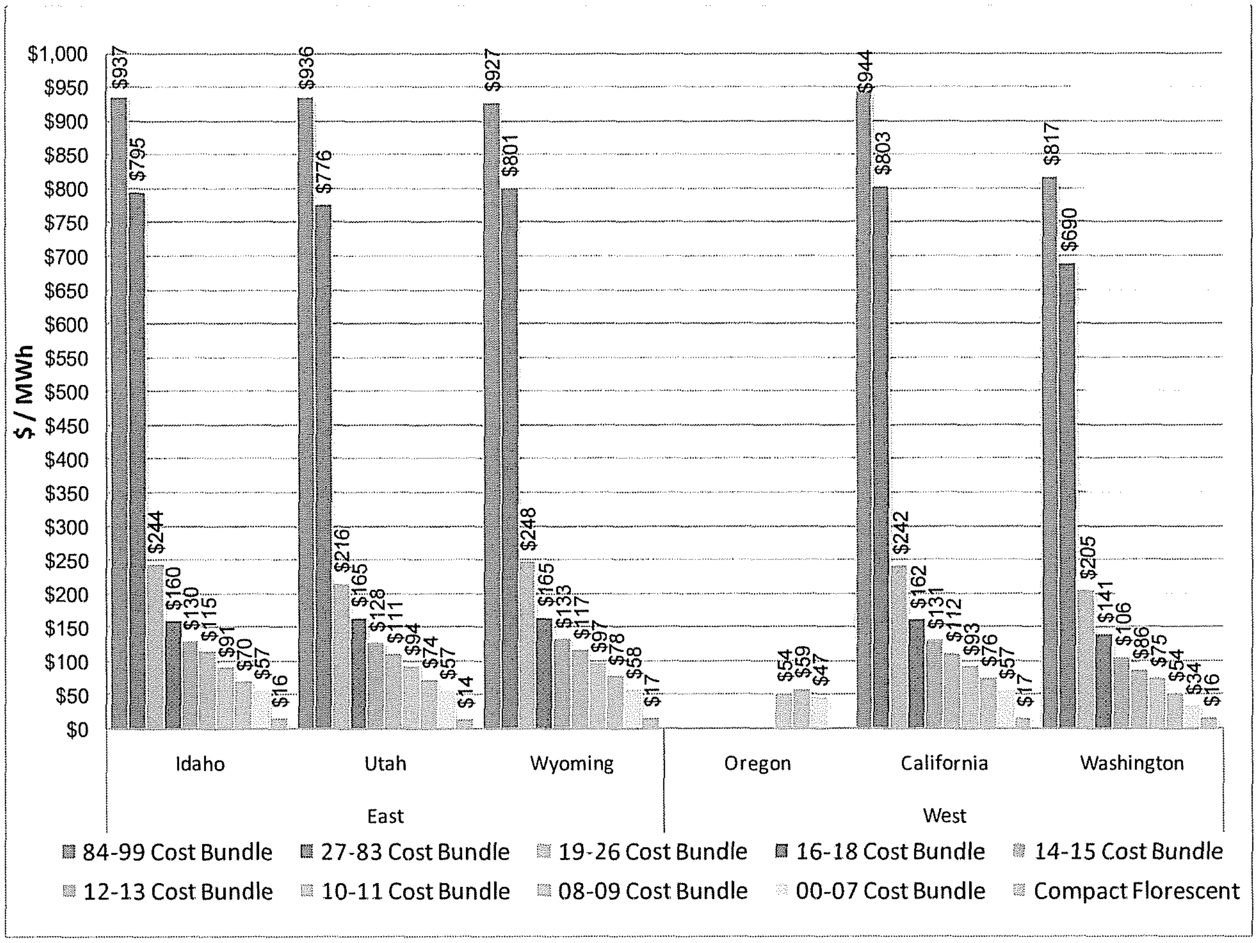
- A transmission and distribution investment deferral credit of $54/kW-year
- Stochastic risk reduction credit of $14.98/MWh[48]
- Northwest Power Act 10-percent credit (Washington resources only)[49]

The bundle price can be interpreted as the average levelized cost for the group of measures in the cost range. In specifying the bundle cost breakpoints, narrower cost ranges were defined for the lower-cost resources to improve the cost accuracy for the bundles expected to be selected by the System Optimizer model most frequently. In contrast, the highest-cost bundles were specified with the widest cost breakpoints.

[48] PacifiCorp developed this credit by assessing the upper-tail cost of 2008 IRP portfolios that included large amounts of clean resources (wind and DSM) relative to the upper-tail cost of the 2008 IRP preferred portfolio.

[49] The formula for calculating the $/MWh credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

Figure 6.10 – Class 2 DSM Cost Bundles and Bundle Prices



As shown in Figure 6.10 the potential associated with standard or spiral "twister" CFLs for 2011 and 2012 were provided as separate bundles for two years. Each of the bundles utilized a $0.02/kWh levelized cost and represents the technical and achievable potentials available from this technology prior to the impact of the pending federal lighting standards. Energy savings potentials from these measures are not included in any other years during the planning horizon. However, potential from specialty CFLs and light emitting diode ("LED") measures not directly impacted by the pending lighting standard change are included in lighting resource potentials in all years.

Class 2 DSM resources in Oregon are acquired on behalf of the Company through ETO programs. The ETO provided the Company three cost bundles, weighted and shaped by the end-use measure potential for each year over a twenty-year horizon. Allocating these resources over two load areas in Oregon for consistency with other modeling efforts generated an additional 120 Class 2 DSM supply curves (three cost bundles multiplied by two load areas multiplied by twenty years).

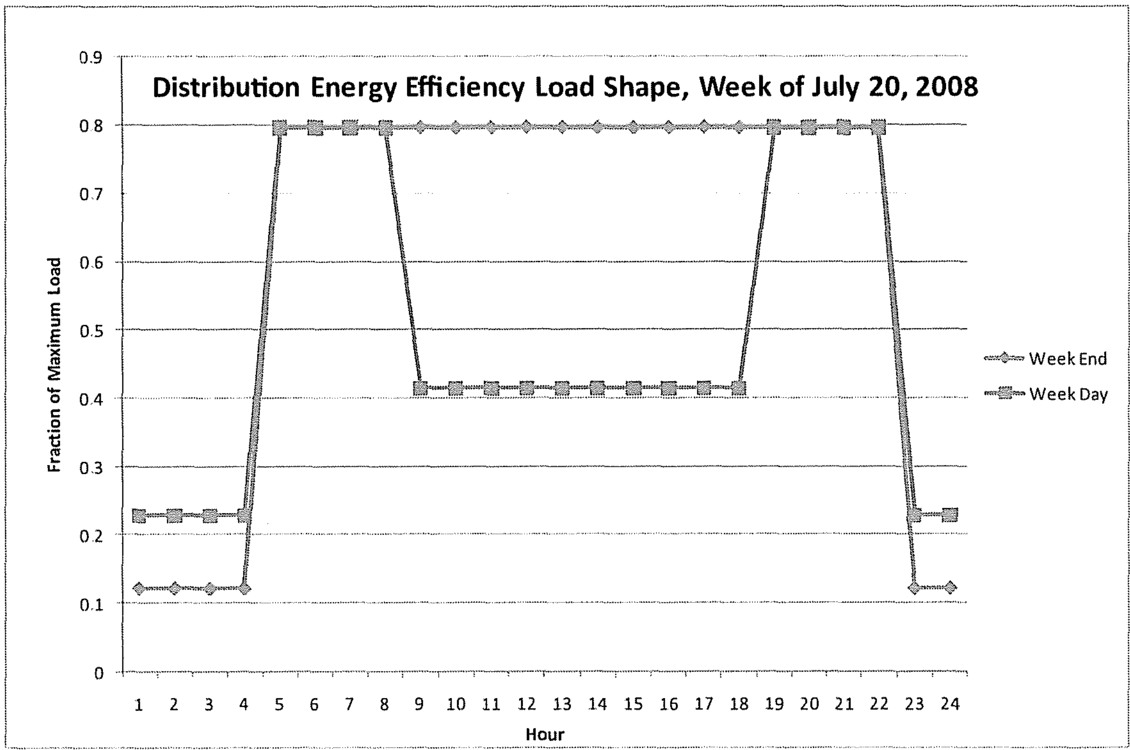
In addition to the program attributes described for the Classes 1 and 3 DSM resources, the Class 2 DSM supply curves also have load shapes describing the available energy savings on an hourly basis. For System Optimizer, each supply curve is associated with an annual hourly ("8760") load shape configured to the 2008 calendar year. These load shapes are used by the model for each simulation year. In contrast, the Planning and Risk model requires for each supply curve a load shape that covers all 20 years of the simulation.

The load shape is composed of fractional values that represent each hour's demand divided by the maximum demand in any hour for that shape. For example, the hour with maximum demand would have a value of 1.00 (100 percent), while an hour with half the maximum demand would have a value of 0.50 (50 percent). Summing the fractional values for all of the hours, and then multiplying this result by peak-hour demand, produces the annual energy savings represented by the supply curve.

Distribution Energy Efficiency

The two resource options, consisting of megawatt capacity potentials (based on six feeders for Walla Walla and 13 feeders for Yakima/Sunnyside), levelized dollars/MWh costs, and daily load shapes, were based on preliminary data provided by the consultant performing the Washington distribution efficiency study. The resource potential is small, totaling only 0.191 MW for Walla Walla and 0.403 MW for Yakima/Sunnyside. The associated levelized resource costs were $63/MWh and $64/MWh, respectively. The load shapes use a representative day pattern for weekdays and weekends. Figure 6.11 shows a sample load shape for the week of July 20, 2008. These load shapes are repeated for each year of the 20-year simulation. The resources are assumed to be available beginning in 2013, and the model can select a fractional amount of the total potential.

Figure 6.11 – Sample Distribution Energy Efficiency Load Shape



Transmission Resources

For this IRP, PacifiCorp investigated seven Energy Gateway scenarios, consisting of various combinations of transmission segments. Preliminary evaluation of the seven scenarios using the System Optimizer model resulted in the selection of four scenarios for portfolio modeling. Detailed information on the scenarios and associated modeling approach and findings are provided in Chapter 4.

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). Front office transactions are proxy resources, assumed to be firm, that represent procurement activity made on an annual forward basis to help the Company cover short positions.

As proxy resources, front office transactions represent a range of purchase transaction types. They are usually standard products, such as heavy load hour (HLH), light load hour (LLH), and/or daily HLH call options (the right to buy or "call" energy at a "strike" price) and typically rely on standard enabling agreements as a contracting vehicle. Front office transaction prices are determined at the time of the transaction, usually via a third party broker and based on the view of each respective party regarding the then-current forward market price for power. An optimal mix of these purchases would include a range in terms for these transactions.

Solicitations for front office transactions can be made years, quarters or months in advance. Annual transactions can be available up to as much as three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

Two front office transaction types were included for portfolio analysis: an annual flat product, and a HLH third quarter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. Third-quarter HLH transactions represent purchases received 16 hours per day, six days per week from July through September. Because these are firm products the counterparties back the full purchase. For example, a 100 MW front office purchase requires the seller to deliver 100 MW to PacifiCorp regardless of circumstance.[50] Thus, to insure delivery, the seller must hold whatever level of reserves as warranted by its system to insure firmness. For this reason, PacifiCorp does not need to hold additional reserves on its 100 MW firm front office purchase. Table 6.18 shows the front office transaction resources included in the IRP models, identifying the market hub, product type, annual megawatt capacity limit, and availability.

[50] Typically, the only exception would be under force majeure. Otherwise, the seller is required to deliver the full amount even if the seller has to acquire it at an exorbitant price.

Table 6.18 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and 3 rd Quarter Heavy Load Hour ("6x16")	400 MW + 375 MW with 10% price premium, 2011-2030
California Oregon Border (COB) Flat Annual ("7x24") and 3 rd Quarter Heavy Load Hour ("6x16")	400 MW, 2011-2030
Southern Oregon / Northern California 3rd Quarter Heavy Load Hour ("6x16")	50 MW, 2011-2030
Mead 3 rd Quarter, Heavy Load Hour (6x16)	190 MW, 2011-2012 264 MW, 2013-2014 100 MW, 2015-2016 0 MW, 2017+
Mona 3 rd Quarter, Heavy Load Hour (6x16)	200 MW, 2011-2012 300 MW, 2013+
Utah North 3 rd Quarter, Heavy Load Hour (6x16)	250 MW, 2011-2030

To arrive at these maximum quantities, PacifiCorp considered the following:

- Historical operational data and institutional experience with transactions at the market hubs.
- The Company's forward market view, including an assessment of expected physical delivery constraints and market liquidity and depth.
- Financial and risk management consequences associated with acquiring purchases at higher levels, such as additional credit and liquidity costs.

Prices for front office transaction purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges.

For this IRP, the Public Utility Commission of Oregon directed PacifiCorp to evaluate intermediate-term market purchases as resource options and assess associated costs and risks.[51] In formulating market purchase options for the IRP models, the Company lacked cost and quantity information with which to discriminate such purchases from the proxy FOT resources already modeled in this IRP. Lacking such information, the Company anticipated using bid information from the All-Source RFP reactivated in December 2009, if applicable, to inform the development of intermediate-term market purchase resources for modeling purposes. The Company received no intermediate-term market purchase bids; therefore, such resources were not modeled for this IRP.

[51] Public Utility Commission of Oregon, In the Matter of PacifiCorp, dba Pacific Power 2007 Integrated Resource Plan, Docket No. LC 42, Order No. 08-232, April 4, 2008, p. 36.

CHAPTER 7 – MODELING AND PORTFOLIO EVALUATION APPROACH

Chapter Highlights

The IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios. The 2011 IRP modeling approach consists of seven phases:

1. *Define input scenarios for portfolio development—referred to as "cases".*
2. *Price forecast development.*
3. *Optimized portfolio development using PacifiCorp's System Optimizer capacity expansion model.*
4. *Monte Carlo production cost simulation of each optimized portfolio.*
5. *Selection of top-performing portfolios using a two-phase screening process that incorporates stochastic portfolio cost and risk assessment measures.*
6. *Deterministic risk assessment of top-performing portfolios.*
7. *Preliminary preferred portfolio selection, followed by resource acquisition risk analysis and determination of the final preferred portfolio.*

PacifiCorp defined 67 portfolio cases covering Energy Gateway transmission scenarios, core cases for preferred portfolio selection (focusing on CO_2 tax level, CO_2 regulation type, natural gas prices, and federal renewable resource policies), and sensitivity cases reflecting the addition of incremental costs for existing coal plants, alternative load forecasts, renewable generation cost and acquisition incentives, and demand-side management resource availability assumptions.

Three underlying natural gas price forecasts (low, medium, and high) were used to develop gas price projections based on CO_2 cost assumptions: no CO_2 tax; medium ($19/ton in 2015 escalating to $29/ton by 2030); high ($25/ton in 2015 escalating to $68/ton by 2030); low-to-very-high ($12/ton in 2015 escalating to $93/ton by 2030).

Top-performing portfolios were selected on the basis of the combination of lowest average portfolio cost and worst-case portfolio cost resulting from 100 Monte Carlo simulation runs. The Monte Carlo runs capture stochastic behavior of electricity prices, natural gas prices, loads, thermal unit availability, and hydro availability.

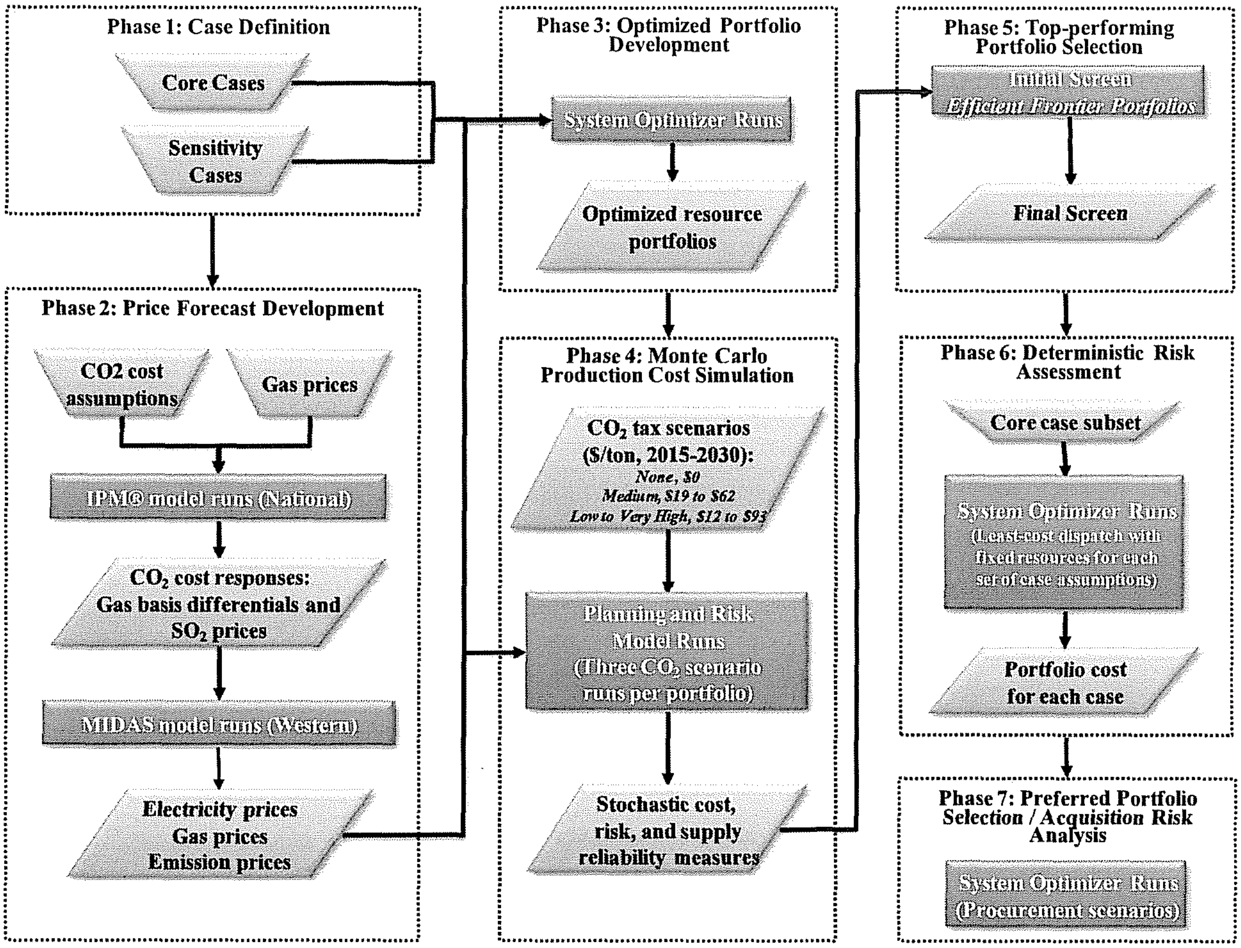
Final preferred portfolio selection considers additional criteria such as risk-adjusted portfolio cost, the 10-year customer rate impact, CO_2 emissions, supply reliability, resource diversity, and future uncertainty/risk of greenhouse gas and RPS policies.

Introduction

The IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation. This chapter describes the modeling and risk analysis process that supported that portfolio performance evaluation. The information drawn from this process, summarized in Chapter 8, was used to help determine PacifiCorp's preferred portfolio and support the analysis of resource acquisition risks.

The 2011 IRP modeling approach consists of seven phases: (1) define input scenarios—referred to as *cases*—characterized by alternative carbon dioxide costs, commodity gas prices, wholesale electricity prices, load growth trends, and other cost drivers, (2) case-specific price forecast development, (3) optimized portfolio development for each case using PacifiCorp's System Optimizer capacity expansion model, (4) Monte Carlo production cost simulation of each optimized portfolio to support stochastic risk analysis, (5) selection of top-performing portfolios using a two-phase screening process that incorporates stochastic portfolio cost and risk assessment measures, (6) deterministic risk analysis using System Optimizer, and (7) preliminary preferred portfolio selection, followed by acquisition risk analysis of preferred portfolio resources and determination of the final preferred portfolio. Figure 7.1 presents the seven phases in flow chart form, showing the main process steps, data flows, and models involved for each phase. General modeling assumptions and price inputs are covered first in this chapter, followed by a profile of each modeling phase.

Figure 7.1 – Modeling and Risk Analysis Process



General Assumptions and Price Inputs

Study Period and Date Conventions

PacifiCorp executes its IRP models for a 20-year period beginning January 1, 2011 and ending December 31, 2030. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year. The System Optimizer model requires in-service dates designated as the first day of a given month, while the Planning and Risk production cost simulation model allows any date.

Escalation Rates and Other Financial Parameters

Inflation Rates

The IRP model simulations and price forecasts reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. For the System Optimizer model, a single escalation rate value is used. This value, 1.8 percent, is estimated as the average of the annual corporate inflation rates for the period 2011 to 2030, using PacifiCorp's September 2010 inflation curve. PacifiCorp's inflation curve is a straight average of the Gross Domestic Product (GDP) inflator and Consumer Price Index (CPI).

Discount Factor

The rate used for discounting in financial calculations is PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2011 IRP is 7.17 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[52]

For the 2011 IRP Update, to be prepared and filed with state commissions in 2012, PacifiCorp plans to conduct a sensitivity analysis of the impact of a lower discount rate on resource selection using the System Optimizer capacity expansion model. This sensitivity analysis was recommended by Commission Staff in the Idaho Public Utility Commission's PacifiCorp 2008 IRP "acceptance of filing" document. PacifiCorp will use the U.S. Treasury Department's published long-term composite fix-coupon bond rates to specify an alternative discount rate value. For 2010, the average of daily rates is about 4 percent.

Federal and State Renewable Resource Tax Incentives

In February 2009, Congress granted another extension of the renewable PTC through December 31, 2012. The current tax credit of $21.5/MWh, which applies to the first ten years of commercial operation for wind, geothermal, and biomass resources, is converted to a levelized net present value after grossing up for income taxes and added to the resource capital cost for entry into the System Optimizer model. The renewable PTC, or an equivalent federal financial incentive, is assumed to be available through December 31, 2014, as a base assumption for resource portfolio modeling.

Utah renewable resources (wind, geothermal, and solar facilities) also incorporate the current Renewable Energy Tax Credit of $3.5/MWh over four years. Oregon's Business Energy Tax Credit has been removed from consideration given that the credit has been scaled back and does not apply to projects completed after July 1, 2012.

The Emergency Economic Stabilization Act of 2008 (P.L. 110-343) allows utilities to claim the 30-percent investment tax credit for solar facilities placed in service by January 1, 2017. This tax credit is factored into the capital cost for solar resource options in the System Optimizer model.

Asset Lives

Table 7.1 lists the generation resource asset book lives assumed for levelized fixed charge calculations.

[52] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

Table 7.1 – Resource Book Lives

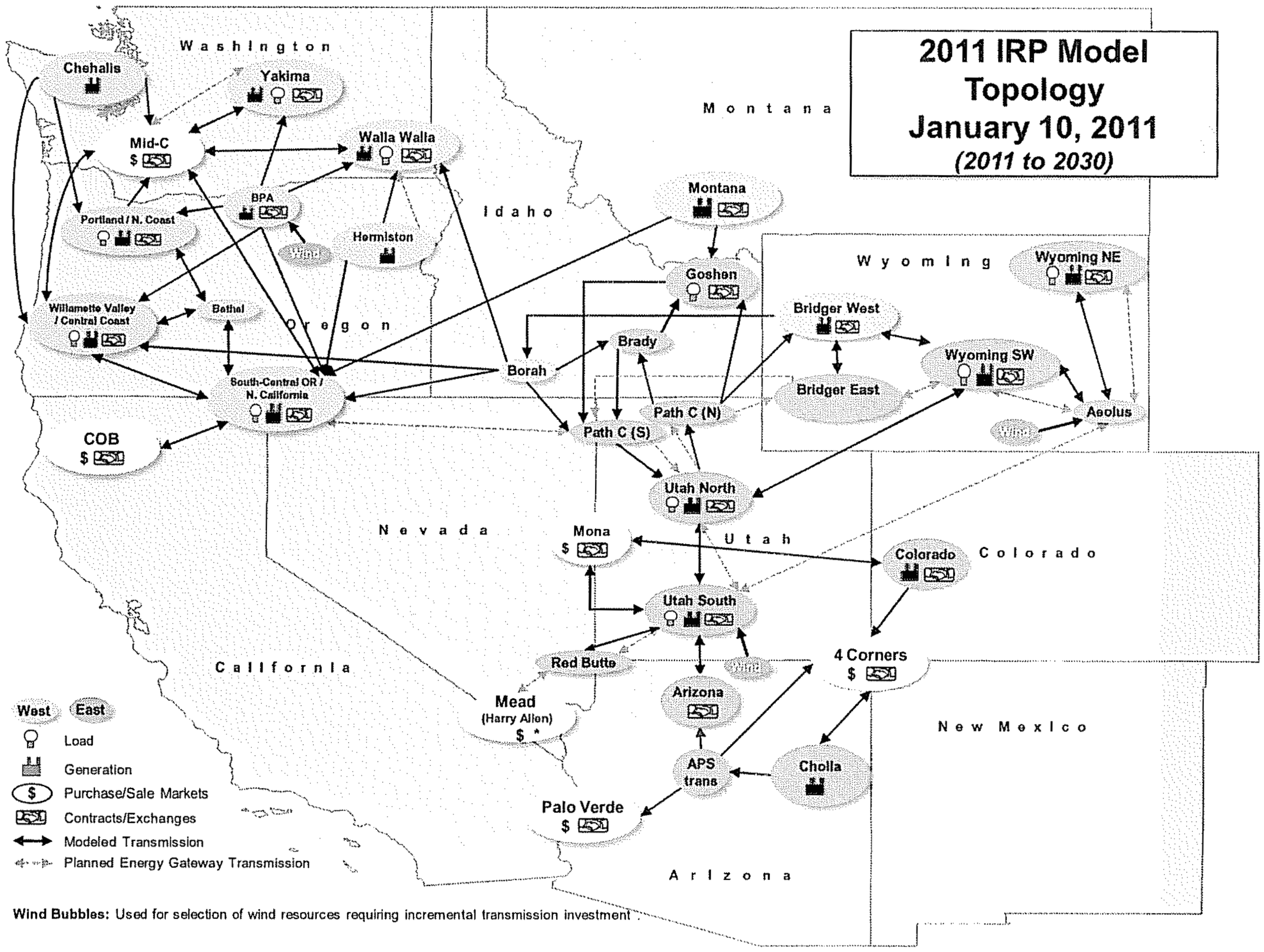
Resource	Book Life (Years)
Supercritical pulverized coal/Integrated Gasification Combined-Cycle	40
Coal plant retrofit with carbon capture and sequestration	20
Combined Cycle Combustion Turbine	40
Pumped Storage	50
Simple Cycle Combustion Turbine (SCCT) Frame	35
Geothermal	40
Solar Photovoltaic	25
Solar Thermal	30
Compressed Air Energy Storage	30
Single Cycle Combustion Turbine (SCCT) Frame	35
Intercooled Aeroderivative SCCT	30
Internal Combustion Engine	30
Fuel Cells	25
Utility-Scale Combined Heat & Power (CHP)	25
Wind	25
Battery Storage	30
Biomass	30
Hydrokinetic, Wave - Floating Buoy	20
Nuclear Plant	40
CHP-Reciprocating Engine	20
CHP - Gas Turbine	20
CHP - Microturbine	15
CHP - Fuel Cell	10
CHP - Commercial Biomass, Anaerobic Digester	15
CHP - Industrial Biomass Waste	15
Solar - Rooftop Photovoltaic	30
Solar - Water Heaters	15
Solar - Attic Fans	10
Dispatchable Standby Generators	20
Microturbine	15

Transmission System Representation

PacifiCorp uses a transmission topology consisting of 19 bubbles (geographical areas) in its eastern control area and 15 bubbles in its western control area designed to best describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Firm transmission paths link the bubbles. The transfer capabilities for these links represent PacifiCorp Merchant function's current firm rights on the transmission lines. This topology is defined for both the System Optimizer and Planning and Risk models, and was also used for IRP modeling support for PacifiCorp's 2011 business plan.

Figure 7.2 shows the IRP transmission system model topology. Segments of the planned Energy Gateway Transmission Project are indicated with red dashed lines.

Figure 7.2 – Transmission System Model Topology



The most significant change to the model topology from the one used for the 2008 IRP Update is the disaggregation of the previously named "West Main" bubble into four new bubbles: Portland/North Coast, Willamette Valley/Central Coast, South-Central Oregon/Northern California and the Bethel Substation. This disaggregation supports a more refined view of Oregon load areas and transmission constraints, mainly to capture benefits of the Hemingway – Boardman – Bethel ("Cascade Crossing") transmission project option described in Chapter 6. Links from the Chehalis generation bubble to these new bubbles were added to better represent generation exports.

Finally, PacifiCorp added special wind generation bubbles to Oregon, Utah, and Wyoming to enable assignment of applicable incremental transmission investment costs to wind selected by the model for Energy Gateway transmission scenario studies.

Carbon Dioxide Regulatory Compliance Scenarios

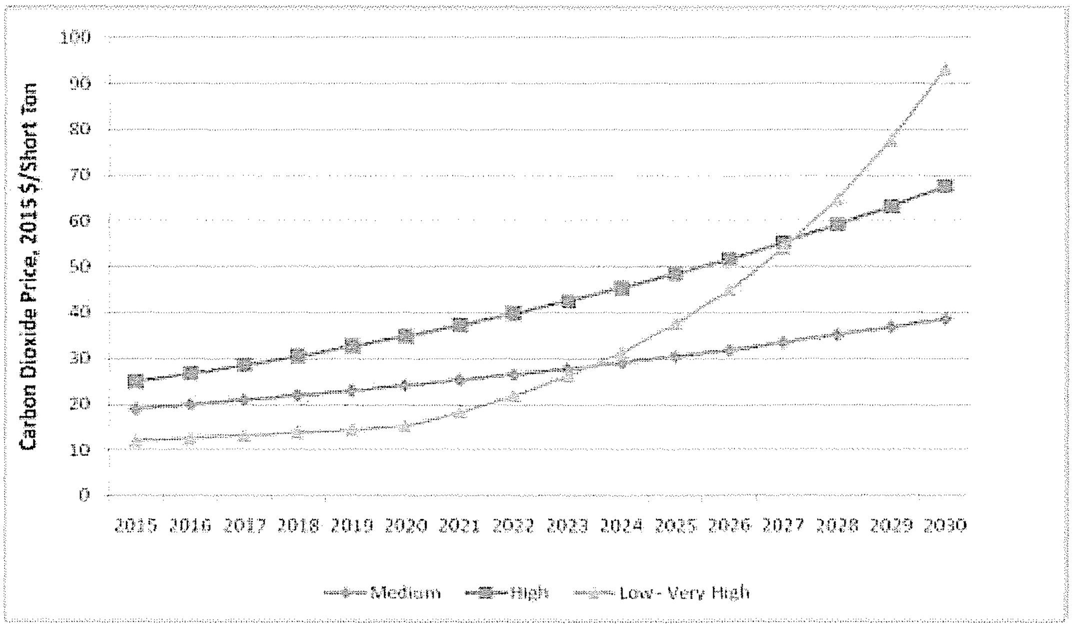
Carbon Dioxide Tax Scenarios

Table 7.2 shows the four CO_2 tax scenarios developed for the IRP. The Medium and High scenarios reflect CO_2 price trajectories contained in recent federal greenhouse gas emission policy proposals, and assume a 2015 start date. The Medium scenario assumes a starting cost of $19 per short ton (2015 dollars) beginning in 2015, with 3 percent annual real escalation plus annual inflation. The High scenario assumes a starting cost of $25 per short ton (2015 dollars) beginning in 2015, with 5 percent annual real escalation plus annual inflation. The Low to Very High scenario assumes a starting cost of $12 per short ton (2015 dollars) beginning in 2015, with 3 percent annual real escalation plus annual inflation through 2020; beginning in 2021, the cost escalates at an 18% annual escalation rate plus inflation. Figure 7.3 is a comparison of the three CO_2 tax trajectories.

Table 7.2 – CO_2 Tax Scenarios

	CO_2 Price, 2015$/short ton			
Year	**None**	**Medium**	**High**	**Low to Very High**
2015	0.00	19.00	25.00	12.00
2016	0.00	19.93	26.73	12.59
2017	0.00	20.93	28.60	13.22
2018	0.00	21.97	30.60	13.88
2019	0.00	23.05	32.71	14.56
2020	0.00	24.18	34.97	15.27
2021	0.00	25.34	37.34	18.30
2022	0.00	26.53	39.85	21.90
2023	0.00	27.81	42.55	26.24
2024	0.00	29.14	45.45	31.43
2025	0.00	30.54	48.54	37.65
2026	0.00	32.00	51.84	45.11
2027	0.00	33.57	55.42	54.09
2028	0.00	35.22	59.24	64.85
2029	0.00	36.94	63.33	77.75
2030	0.00	38.75	67.70	93.23

Figure 7.3 – Carbon Dioxide Price Scenario Comparison



Emission Hard Cap Scenarios

PacifiCorp also modeled two CO_2 system emission hard caps scenarios as alternate compliance mechanisms.[53] Two emission cap scenarios were developed:

- Base: 15 percent below 2005 levels by 2020, and 80% by 2050
- Oregon: 10 percent below 1990 levels by 2020—the Oregon target in H.B. 3543—and 80 percent below by 2050

The hard caps go into effect in 2015. Table 7.3 shows the hard cap emission limits for each scenario.

Table 7.3 – Hard Cap Emission Limits (Short Tons)

Year	Base Emission Limits (15% below 2005 Levels by 2020; 80% by 2050)	Oregon H.B. 3543 Emission Limits (10% below 1990 Levels by 2020; 80% by 2050)
1990		49,878
2005	60,938	
2015	56,968	51,075
2016	55,934	49,838
2017	54,900	48,601
2018	53,866	47,364
2019	52,832	46,127

[53] The Public Utility Commission of Oregon's 2008 IRP acknowledgment order (Order No. 10-066 under Docket No. LC 47) included a requirement to provide analysis of potential hard cap regulations.

Year	Base Emission Limits (15% below 2005 Levels by 2020; 80% by 2050)	Oregon H.B. 3543 Emission Limits (10% below 1990 Levels by 2020; 80% by 2050)
2020	51,798	44,890
2021	50,477	43,726
2022	49,157	42,562
2023	47,837	41,398
2024	46,516	40,235
2025	45,196	39,071
2026	43,876	37,907
2027	42,555	36,743
2028	41,235	35,579
2029	39,915	34,416
2030	38,594	33,252
2050	12,188	9,976

For representing CO_2 emissions associated with firm market purchases and system balancing spot market transactions, PacifiCorp's reporting protocols for calculating its greenhouse gas inventory requires using the EPA's e-Grid sub-region output emission factors for unspecified market transactions. Consequently, the CO_2 emission rate of 902 lbs/MWh is applied for the Mid-Columbia, COB, Mona, and Mead markets, and 1,300 lbs/MWh is applied for the Palo Verde and Four Corners markets.

When modeling a hard cap in System Optimizer, the model generates shadow emission prices in order to meet the hard cap. For example, if the hard cap is not met then the shadow price is increased to decrease the output of the emission-producing stations. These shadow prices are imported into the PaR model to simulate emission-constrained dispatch. Table 7.4 shows the shadow prices generated for the four hard cap cases. The medium CO_2 tax is also used for hard cap cases to reflect assumed regional or federal emission prices that impact wholesale electricity and gas commodity prices used for portfolio modeling. Note that for PaR portfolio cost reporting, PacifiCorp applied the CO_2 tax values to emission quantities rather than the System Optimizer shadow costs to maintain cost comparability among the portfolios.

Table 7.4 – CO_2 Emission Shadow Costs Generated by System Optimizer for Emission Hard Cap Scenarios

Case	15	16	17	18
Hard Cap	Base	Base	Base	Oregon H.B. 3543
Gas Price	Low	Medium	High	Medium
Year	Shadow CO_2 Emission Price ($/ton)			
2015	0	0	0	37
2016	10	8	1	39
2017	11	24	16	35
2018	14	30	34	37
2019	15	34	39	40
2020	17	36	50	43
2021	21	40	64	47
2022	24	43	71	55
2023	28	50	78	70

Case	15	16	17	18
Hard Cap	Base	Base	Base	Oregon H.B. 3543
Gas Price	Low	Medium	High	Medium
Year	Shadow CO_2 Emission Price ($/ton)			
2024	34	57	85	75
2025	38	60	91	75
2026	47	64	94	77
2027	47	62	95	73
2028	51	71	108	83
2029	63	75	114	101
2030	47	61	78	78

Oregon Environmental Cost Guideline Compliance

The Public Utility Commission of Oregon, in their IRP guidelines, directs utilities to construct a base-case scenario that reflects what it considers to be the most likely regulatory compliance future for CO_2, as well as alternative scenarios "ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities." Modeling portfolios with no CO_2 cost represents the current regulatory level. The Medium scenario was considered the most likely regulatory compliance scenario at the time that IRP CO_2 scenarios were being prepared and vetted by public stakeholders (early fall of 2010). Given the late-2010 collapse of comprehensive federal energy legislation and loss of momentum for implementing federal carbon pricing schemes, there is no "likely" regulatory compliance future at the present time (notwithstanding the U.S. EPA's GHG initiative to revise New Source Performance Standards for electric generating units.) PacifiCorp believes that its CO_2 tax and hard cap scenarios reflect a reasonable range of compliance futures for meeting the Public Utility Commission of Oregon scenario development guideline given continued uncertainty. In particular, it should be noted that the hard cap shadow prices for Case 15 exhibit a more moderate trajectory than the Medium scenario, effectively providing a "low" CO_2 tax case for portfolio evaluation.

Case Definition

The first phase of the IRP modeling process was to define the cases (input scenarios) that the System Optimizer model uses to derive optimal resource expansion plans. The cases consist of variations in inputs representing the predominant sources of portfolio cost variability and uncertainty. PacifiCorp generally specified low, medium, and high values to ensure that a reasonably wide range in potential outcomes is captured. For the 2011 IRP, PacifiCorp developed a total of 49 cases.

PacifiCorp defined three types of cases: Energy Gateway scenario evaluation cases, core cases, and sensitivity cases. Energy Gateway scenario evaluation cases were designed to help PacifiCorp's transmission planning department evaluate four Energy Gateway expansion options based on System Optimizer portfolio modeling results. These 16 cases supplement other Energy Gateway economic analysis conducted with the IRP models, profiled in Appendix C.

Core cases focus on broad comparability of portfolio performance results for four key variables. These variables include (1) the level of a per-ton CO_2 tax, (2) the type of CO_2 regulation—tax or hard emission cap, (3) natural gas and wholesale electricity prices based on PacifiCorp's forward price curves and adjusted as necessary to reflect CO_2 tax impacts, and (4) extension date for the federal renewables production tax credit. The Company developed 19 core cases based on a combination of input variable levels. The core case group includes a 2011 business plan "reference" portfolio. This portfolio consists of fixed wind and gas resources for 2011 through 2020, reflecting the major generation projects in the business plan. Also included are four hard cap cases. Because these cases simulate physical emission constraints as opposed to generator emission costs, they do not have emissions profiles comparable to the other portfolios.

In contrast, sensitivity cases focus on changes to resource-specific assumptions and alternative load growth forecasts. The resulting portfolios from the sensitivity cases are typically compared to one of the core case portfolios. PacifiCorp developed 14 sensitivity cases reflecting evaluation of existing coal plant operation, alternative load forecasts, alternative renewable generation cost and acquisition incentives, and demand-side management resource availability assumptions.

In developing these cases, PacifiCorp kept to a target range in terms of the total number (low 50s) in light of the data processing and model run-time requirements involved. To keep the number of cases within this range, PacifiCorp excluded some core cases with improbable combinations of certain input levels, such as a high CO_2 tax and high load growth. (With a high CO_2 tax, a significant amount of demand reduction is expected to occur in the form of energy efficiency improvements, and utility load control programs.)

PacifiCorp also relied heavily on feedback from public stakeholders. The Company assembled an initial set of cases in July 2010, and introduced them to stakeholders at the August 8, 2010, public input meeting. Subsequent updates based on stakeholder comments and Company refinements were reviewed at public input meetings held October 5 and December 15, 2010. One of the key messages from stakeholders was to ensure that the range of cases generate a diverse set of resource types.[54]

Case Specifications

Table 7.5 profiles the portfolio development cases specifications. Reference numbers in the table headings and certain rows correspond to notes providing descriptions of the case variables and explanatory remarks for specific cases that follow the table.

[54] PacifiCorp's IRP public process IRP Web page includes links to documentation on portfolio case development and how stakeholder comments were addressed.

Table 7.5 – Portfolio Case Definitions

Case #	Assumption Alternatives									
	Carbon Policy		Gas Price 2/	Load Growth 3/	Renewable PTC and Wind Integration Cost 4/	Renewable Portfolio Standards 5/	Demand-Side Management	Distributed Solar 10/	Coal Plant Utilization	Energy Gateway Trans 12/
	Type 1/ CO2 Tax Hard Cap	Cost Medium High Low to Very High	Low Medium High	Low Econ. Growth Medium Econ. Growth High Growth High Peak Demand	Extension to 2015 Extension to 2020 Alt. Wind Integ. Cost	None Current RPS Federal RPS	High Achievable 6/ Class 3 Included 7/ Technical Potential 8/ Distribution Efficiency 9/	Current Incentives UT Buydown Levels	No shutdowns Optimized 11/	Base Scenario 1 Scenario 2 Scenario 3
Energy Gateway Scenario Evaluation Cases										
EG1	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG2	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG3	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG4	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG5	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG6	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG7	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG8	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG9	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG10	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG11	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG12	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG13	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG14	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG15	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG16	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG1-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG2-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG3-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG4-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG5-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG6-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG7-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG8-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG9-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG10-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG11-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG12-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG13-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG14-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG15-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG16-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3

Case #	Assumption Alternatives									
	Carbon Policy		Gas Price 2/	Load Growth 3/	Renewable PTC and Wind Integration Cost 4/	Renewable Portfolio Standards 5/	Demand-Side Management	Distributed Solar 10/	Coal Plant Utilization	Energy Gateway Trans 12/
	Type 1/ CO2 Tax Hard Cap	Cost Medium High Low to Very High	Low Medium High	Low Econ. Growth Medium Econ. Growth High Growth High Peak Demand	Extension to 2015 Extension to 2020 Alt. Wind Integ. Cost	None Current RPS Federal RPS	High Achievable 6/ Class 3 Included 7/ Technical Potential 8/ Distribution Efficiency 9/	Current Incentives UT Buydown Levels	No shutdowns Optimized 11/	Base Scenario 1 Scenario 2 Scenario 3
Core Cases										
1	None	None	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
2	None	None	Medium	Med. Econ. Growth	Extension to 2015	None	High Achievable	Current Incentives	None	Base or Scenario
3	CO2 Tax	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
4	CO2 Tax	High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
5	CO2 Tax	Low to Very High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
6	CO2 Tax	Low to Very High	Low	Med. Econ. Growth	Extension to 2020	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
7	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
8	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
9	CO2 Tax	Low to Very High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
9a	Same assumptions as 9, except using two System Optimizer runs; the first, a 12-year run, determines fixed resources for a subsequent 20-year run 13/									
10	CO2 Tax	Low to Very High	Medium	Med. Econ. Growth	Extension to 2020	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
11	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
12	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
13	CO2 Tax	Low to Very High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
14	CO2 Tax	Low to Very High	High	Med. Econ. Growth	Extension to 2020	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
15	Hard Cap - Base	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
16	Hard Cap - Base	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
17	Hard Cap - Base	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
18	Hard Cap - OR	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
19	2011 Business Plan resources fixed through 2020; optimized thereafter using Medium scenario assumptions								None	Scenario 3
Coal Plant Utilization Sensitivity Cases										
20	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
21	CO2 Tax	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
22	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
23	CO2 Tax	High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
24	Hard Cap - Base	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
Load Forecast Sensitivity Cases										
25	CO2 Tax	Medium	Medium	Low Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
26	CO2 Tax	Medium	Medium	High Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
27	CO2 Tax	Medium	Medium	High Peak Demand	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
Renewable Resource Sensitivity Cases										
28	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	None	High Achievable	Current Incentives	None	Base or Scenario
29	CO2 Tax	Medium	Medium	Med. Econ. Growth	Alt. Wind Integ. Cost	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
30	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	UT $1.50/Watt Incentive	None	Base or Scenario
30a	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	UT $2.00/Watt Incentive	None	Base or Scenario
DSM Sensitivity Cases										
31	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Class 3 Included	Current Incentives	None	Base or Scenario
32	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Technical Potential	Current Incentives	None	Base or Scenario
33	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Distribution Energy	Current Incentives	None	Base or Scenario

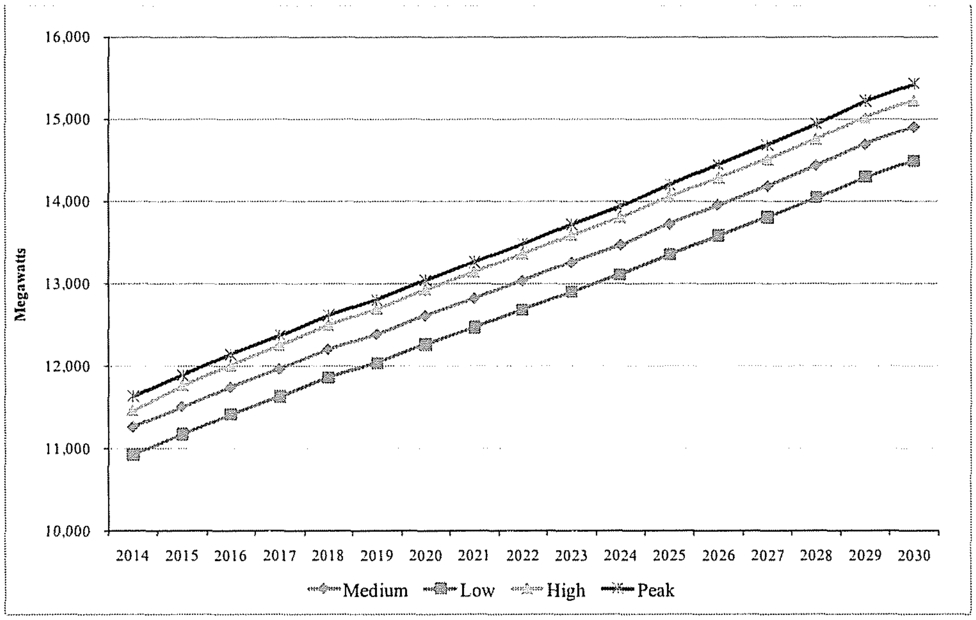
Case Definition Notes

1. The carbon dioxide tax is a variable cost adder for each short ton of CO_2 emitted by PacifiCorp's thermal plants. The CO_2 tax for market purchases is incorporated in the electricity price forecast scenarios as simulated by MIDAS, a regional production simulation model that is described later in this chapter. These marginal wholesale electricity price forecasts, by market hub, are then fed into System Optimizer. The hard cap is a physical CO_2 emissions limit placed on system generation and purchases.

2. The high, medium, and low natural gas price forecasts are based on a review of multiple forecasting service company projections, and incorporate the CO_2 tax assumptions associated with the case definitions. Details on the price forecasts and supporting methodology are provided later in this chapter.

3. The main purpose of the alternative load forecast cases is to determine the resource type and timing impacts resulting from a structural change in the economy. The focus of the load growth scenarios is from 2014 onward. The Company assumes that economic changes begin to significantly impact loads beginning in 2014, the currently planned acquisition date for the next CCCT resource. For the low economic growth scenario (Case 25), another economic recession hits in 2014. For the high economic growth scenario (Case 26), the economy is assumed to fully recover from the current recession by 2014 and significantly expand beginning at that point. Low and high load forecasts are one-percent decreases and increases, respectively, for economic drivers, relative to the Medium forecast. PacifiCorp developed the "high peak demand" forecast by assuming one-in-ten (10 percent probability of exceedence) high temperature loads. Figure 7.4 shows the low, high, and high-peak load forecasts relative to the medium case. Note that the capacities reflect loads before any adjustments for demand-side management programs are applied. See Appendix A for a detailed description of the forecast scenarios.

Figure 7.4 – Load Forecast Scenario Comparison



4. The "PTC extension to 2015" assumption is consistent with PacifiCorp's 2011 business plan. The "PTC extension to 2020" assumption was recommended by a public stakeholder.

   A wind integration cost of $5.38/MWh (versus $9.70/MWh as reported in PacifiCorp's wind integration study dated September 1, 2010) was used for the alternative wind integration cost case as recommended by Renewable Northwest Project based on their independent analysis. The PTC is assumed to expire by 2015 for the alternate wind integration cost case.

5. The current RPS assumption is a system-wide requirement based on meeting existing state RPS targets under the Multi-State Protocol Revised Protocol. States with applicable resource standards include California, Oregon, Washington, and Utah. The table below shows the incremental system renewable energy requirement after accounting for state eligible resources acquired through 2010. Based on RPS compliance analysis using the compliance targets proposed by Senator Jeff Bingaman, along with PacifiCorp's eligible renewable resources through 2010, PacifiCorp would comply with this federal RPS proposal until 2030. The federal RPS scenario assumes the higher Waxman-Markey (H.R. 2454) targets that passed the U.S. House of Representatives in June 2009. This RPS scenario was used for Energy Gateway and 2011 IRP preferred portfolio scenario analysis. Table 7.6 below compares the Bingaman and Waxman-Markey combined renewables/electricity savings compliance targets and the renewable-only targets estimated by PacifiCorp.

Table 7.6 – Comparison of Renewable Portfolio Standard Target Scenarios

		Bingaman		Waxman-Markey (H.R. 2454)	
Year	Current RPS 1/ (System Basis)	Compliance Target	Renewable Percentage 1/	Compliance Target	Renewable Percentage 2/
2015	0.0%	3.0%	2.3%	9.5%	7.1%
2016	0.0%	3.0%	2.3%	13.0%	9.8%
2017	0.0%	3.0%	2.3%	13.0%	9.8%
2018	0.0%	6.0%	4.5%	16.5%	12.4%
2019	0.0%	6.0%	4.5%	16.5%	12.4%
2020	0.1%	6.0%	4.5%	20.0%	15.0%
2021	2.0%	9.0%	6.8%	20.0%	15.0%
2022	2.2%	9.0%	6.8%	20.0%	15.0%
2023	2.2%	12.0%	9.0%	20.0%	15.0%
2024	2.3%	12.0%	9.0%	20.0%	15.0%
2025	3.2%	15.0%	11.3%	20.0%	15.0%
2026	3.2%	15.0%	11.3%	20.0%	15.0%
2027	3.2%	15.0%	11.3%	20.0%	15.0%
2028	3.2%	15.0%	11.3%	20.0%	15.0%
2029	3.1%	15.0%	11.3%	20.0%	15.0%
2030	3.2%	15.0%	11.3%	20.0%	15.0%

1/ Reflects additional renewable energy requirement after accounting for eligible resources acquired through 2010.
2/ Reflects the forecasted renewable portion of a combined renewable/electricity savings requirement.

6. A high achievable percentage assumption of 85 percent for DSM programs applies to all portfolios. The Cadmus Group's base achievable assumption for the 2007 DSM potential study, prior to Company adjustment, was 55 percent.

7. For sensitivity Case 31, System Optimizer is allowed to select price-responsive DSM programs. These programs, outlined in Chapter 6, include residential time-of-use, commercial/industrial real-time pricing, commercial/industrial demand buyback, commercial/industrial load curtailment, commercial critical peak pricing, and *mandatory* irrigation time-of-use rates.

8. This assumption is intended to meet the Public Service Commission of Utah's DSM evaluation requirements. DSM is modeled based on technical potential.

9. PacifiCorp modeled a Washington-only conservation voltage reduction (CVR) resource based on estimated energy savings and costs for 19 distribution feeders analyzed as part of a consultant study.[55] The sensitivity analysis serves as a proof-of-concept test for future resource modeling. The levelized cost and resource capacity by Washington topology bubble is shown in the following table:

Location	Levelized Average Cost 1/ (2010 $/MWh)	Capacity (MW)
Walla Walla	63	0.191
Yakima	66	0.403

1/ Costs exclude credits applied to meet Initiative 937 methodology requirements documented in Chapter 6.

10. This case is intended to meet the Public Service Commission of Utah's distributed solar evaluation requirements. For Case 30, Utah roof-top PV resources were modeled with a program incentive cost (capital cost) of $1,744/kW, which includes a 14 percent administrative and marketing cost gross-up. For Case 30a, the resources were modeled with a program cost of 2,326/kW, including the 14 percent administrative and marketing cost gross-up. Resource potential in Utah is 1.2 MW per year, reaching 24 MW by 2030.[56]

11. The five coal plant utilization sensitivity cases are designed to investigate, as a modeling proof-of-concept, the impacts of CO_2 cost and gas price scenarios on the existing coal fleet after accounting for: incremental environmental compliance, fueling, decommissioning, and coal contract liquidated damages, as well as recovery of remaining plant depreciation. System Optimizer is allowed to select the optimal coal plant shut down dates. This study is limited to CCCT replacement resources with an earliest in-service date of 2016. The simulation period covers 2011 through 2030. More details on specification of the coal plant utilization model set-up are provided later in this chapter.

[55] The study was conducted by a consulting team led by Commonwealth Associates, Inc. The modeled resource reflects preliminary findings of the study. The consulting team applied the Distribution Efficiency Initiative (DEI) average Pacific Northwest conservation load shape to the 19 distribution feeder efficiency measures to derive hourly energy savings for use by System Optimizer. DEI was a three-year study initiated in 2005 by the Northwest Energy Efficiency Alliance to investigate the cost-effectiveness of distribution efficiency and voltage optimization measures.

[56] Resources are modeled by topology bubble. The Utah solar PV resource was located in the Utah North bubble, which includes a portion of Idaho and southwestern Wyoming. The total solar PV capacity potential per year for Utah North is 1.3 MW, consisting of 1.2 MW for Utah, 0.18 MW for Wyoming, and 0.07 MW for Idaho.

12. Energy Gateway transmission scenarios are defined by including certain transmission expansion segments. Table 7.7 shows the segments assigned to the Energy Gateway scenarios. Capital costs for each scenario included in System Optimizer are also shown. PacifiCorp ultimately developed 32 portfolios reflecting the base RPS assumption and the higher Waxman-Markey targets (Cases designated with a "-WM" extension). Modeling assumptions, transmission maps, and results are provided in Chapter 4.

For the Base scenario, both the Populus - Terminal and Mona - Oquirrh projects have a Certificate of Public Convenience and Necessity (CPCN). The Sigurd - Red Butte and Harry Allen projects are not considered transmission resource options because they are reliability/grid reinforcement investments necessary for serving southwestern Utah loads, and not justified based on supply-side resource expansion elsewhere on the system. The "Hemingway - Boardman - Cascade Crossing" transmission project is treated as a resource option in Scenario 3 due to the dependency on the Populus - Hemingway segment.

Table 7.7 – Energy Gateway Transmission Scenarios

Energy Gateway Segments by Scenarios			
Base	**Scenario 1**	**Scenario 2**	**Scenario 3**
Gateway Central (Populus-Terminal and Mona-Oquirrh)	Gateway Central	Gateway Central	Gateway Central
Sigurd - Red Butte	Sigurd - Red Butte	Sigurd - Red Butte	Sigurd - Red Butte
Harry Allen Upgrade	Harry Allen Upgrade	Harry Allen Upgrade	Harry Allen Upgrade
	Windstar - Populus	**Windstar - Populus**	**Windstar - Populus**
		Aeolus - Mona	**Aeolus - Mona**
			Populus - Hemingway
			Hemingway-Boardman-Cascade Crossing
Total Capital Cost (Million $)			
1,776	3,329	4,609	5,888

13. Two portfolios were developed for Case 9. The portfolio for Case 9 is a conventional 20-year System Optimizer run. Portfolio 9a represents the outcome of two System Optimizer runs; the first run was a 12-year run, while the second run was a 20-year run with the resources fixed for the first ten years based on the 12-year run. (The 12-year run mitigates the optimization period end effects that would be present on a ten year run.) These portfolios are intended to support analysis required in the Public Utility Commission of Oregon's 2008 IRP acknowledgment order (Order No. LC 47). They also support the Oregon Commission's "Trigger Point Analysis" IRP standard (Order No. 08-339).

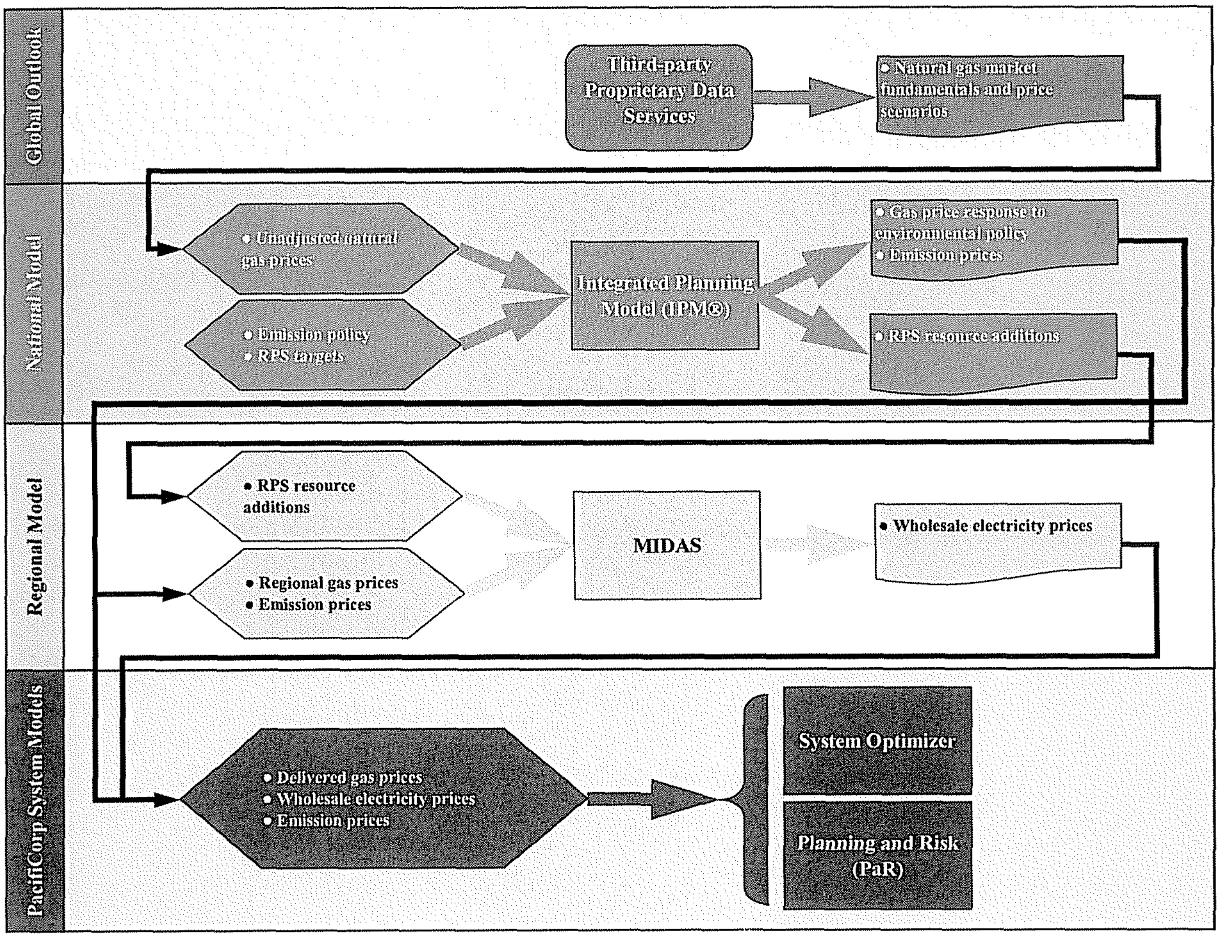
Scenario Price Forecast Development

On a central tendency basis, commodity markets tend to respond to the evolution of supply and demand fundamentals over time. Due to a complex web of cross-commodity interactions, price movements in response to supply and demand fundamentals for one commodity can have implications for the supply and demand dynamics and price of other commodities. This interaction routinely occurs in markets common to the electric sector as evidenced by a strong positive correlation between natural gas prices and electricity prices.

Some relationships among commodity prices have a long historical record that have been studied extensively, and consequently, are often forecasted to persist with reasonable confidence. However, robust forecasting techniques are required to capture the effects of secondary or even tertiary conditions that have historically supported such cross-commodity relationships. For example, the strong correlation between natural gas prices and electricity prices is intrinsically tied to the increased use of natural gas-fired capacity to produce electricity. If for some reason in the future natural gas-fired capacity diminishes in favor of an alternative technology, the linkage between gas prices and electricity prices would almost certainly weaken.

PacifiCorp deploys a variety of forecasting tools and methods to capture cross-commodity interactions when projecting prices for those markets most critical to this IRP – natural gas prices, electricity prices, and emission prices. Figure 7.5 depicts a simplified representation of the framework used by PacifiCorp to develop the price forecasts for these different commodities. At the highest level, the commodity price forecast approach begins at a global scale with an assessment of natural gas market fundamentals. This global assessment of the natural gas market yields a price forecast that feeds into a national model where the influence of emission and renewable energy policies is captured. Finally, outcomes from the national model feed into a regional model where the up-stream gas prices and emission prices drive a forecast of wholesale electricity prices. In this fashion, the Company is able to produce an internally consistent set of price forecasts across a range of potential future outcomes at the pricing points that interface with PacifiCorp's system.

Figure 7.5 – Modeling Framework for Commodity Price Forecasts



The process begins with an assessment of global gas market fundamentals and an associated forecast of North American natural gas prices. In this step, PacifiCorp relies upon a number of third-party proprietary data and forecasting services to establish a range of gas price scenarios. Each price scenario reflects a specific view of how the North American natural gas market will balance supply and demand.

Once a natural gas price forecast is established, the IPM® is used to simulate the entire North American power system. IPM®, a linear program, determines the least cost means of meeting electric energy and capacity requirements over time, and in its quest to lower costs, ensures that all assumed emission policies and RPS policies are met. Concurrently, IPM® can be configured with a dynamic natural gas price supply curve that allows natural gas prices to respond to changes in demand triggered by environmental compliance. Additional outputs from IPM® include a forecast of resource additions consistent with all specified RPS targets, electric energy and capacity prices, coal prices[57], electric sector fuel consumption, and emission prices for policies administered in a cap-and-trade framework.

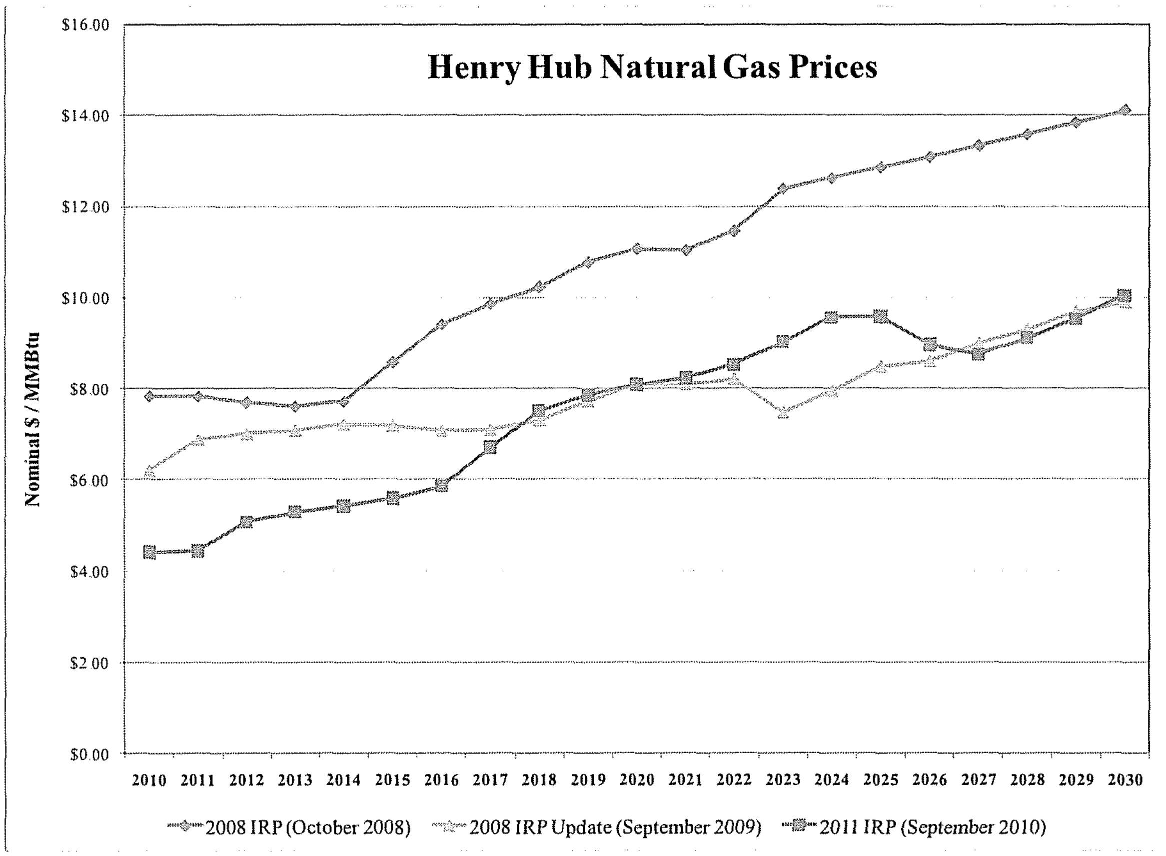
[57] IPM® contains over 70 coal supply curves, with reserve estimates, by rank and quality. Coal supply curves are matched to coal demand areas, including transportation costs, and optimized. As such, IPM® is able to capture coal

Once emission prices and the associated gas price response are forecasted with IPM®, results are used in a regional model named Midas to produce an accompanying wholesale electricity price forecast. Midas is an hourly chronological dispatch model configured to simulate the Western Interconnection and offers a more refined representation of western wholesale electricity markets than is possible with IPM®. Consequently, PacifiCorp produces a more granular price projection that covers all of the markets required for the system models used in the IRP. The natural gas and wholesale electricity price forecasts developed under this framework and used in the cases for this IRP are summarized in the sections that follow.

Gas and Electricity Price Forecasts

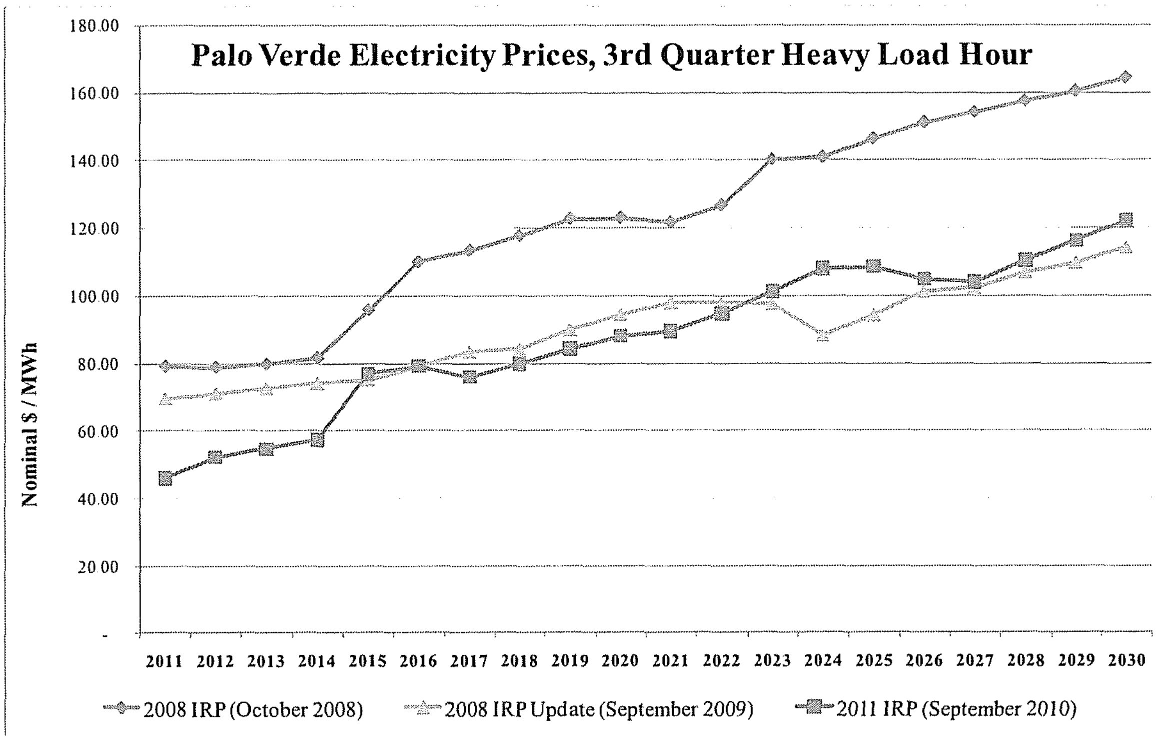
Price forecasts for this IRP are significantly lower than those produced for the Company's 2008 IRP and the subsequent 2008 IRP Update filed with state commissions in March 2010. Figures 7.6 and 7.7 compare natural gas (Henry Hub) and electricity price forecasts, respectively, for the 2011 IRP, 2008 IRP Update, and 2008 IRP.

Figure 7.6 – Comparison of Henry Hub Gas Price Forecasts used for Recent IRPs



price response from incremental (decremental) demand, which ultimately affects the natural gas and emission prices that feed into System Optimizer and PaR.

Figure 7.7 – Comparison of Electricity Price Forecasts used for Recent IRPs



A total of three underlying natural gas price forecasts are used to develop the 15 unique gas price projections for the cases analyzed in this IRP. A range of fundamental assumptions affecting how the North American market will balance supply and demand defines the three underlying price forecasts. Table 7.8 shows representative prices at the Henry Hub benchmark for the three underlying natural gas price forecasts. The three forecasts serve as a point of reference and are adjusted to account for changes in natural gas demand driven by a range of environmental policy and technology assumptions specific to each IRP case. Figure 7.6 compares the Henry Hub price forecasts used for the 2008 IRP, 2008 IRP Update, and 2011 IRP, indicating the large drop in forecasted prices.

Table 7.8 – Henry Hub Natural Gas Price Forecast Summary (nominal $/MMBtu)

Forecast Name	2011	2015	2020	2025	2030
High	$4.41	$8.41	$10.99	$14.55	$15.97
Medium	$4.41	$7.43	$8.09	$9.58	$10.04
Low	$4.41	$4.79	$5.70	$6.75	$7.41

Price Projections Tied to the High Forecast

The underlying high gas price forecast is defined by higher global oil prices and lower LNG and Canadian gas imports, and delayed unconventional gas development. Despite higher gas prices, increases in gas demand for transportation have the effect of offsetting demand decreases in the power generation and industrial sectors. Figure 7.8 summarizes prices at the Henry Hub benchmark and Figure 7.9 summarizes the accompanying electricity prices for the forecasts developed around the high gas price projection.

Figure 7.8 – Henry Hub Natural Gas Prices from the High Underlying Forecast

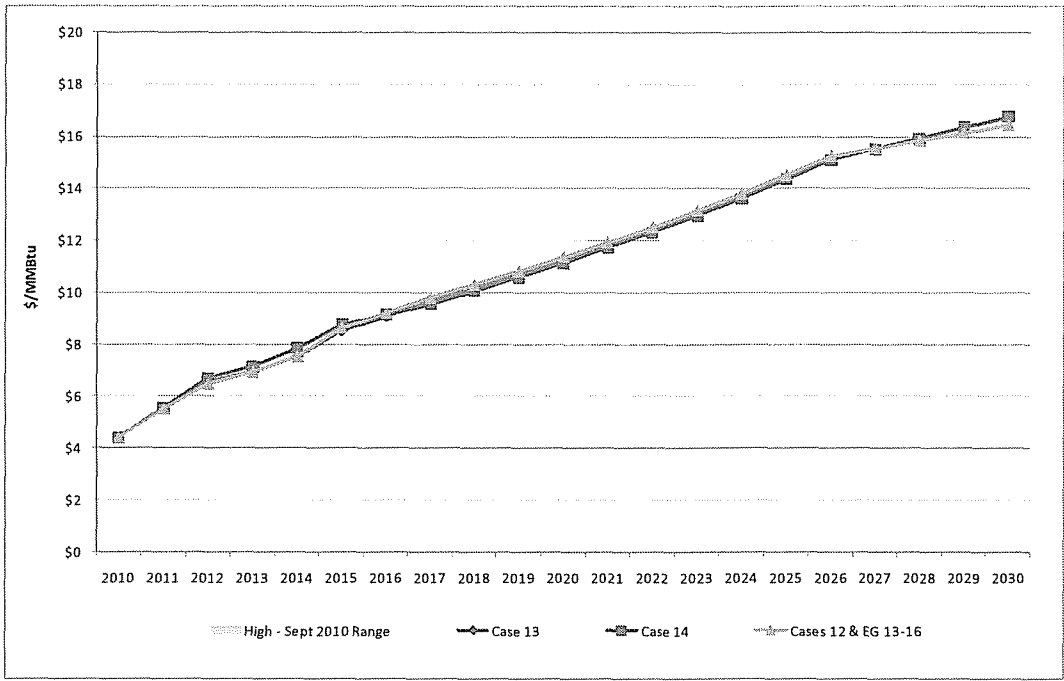
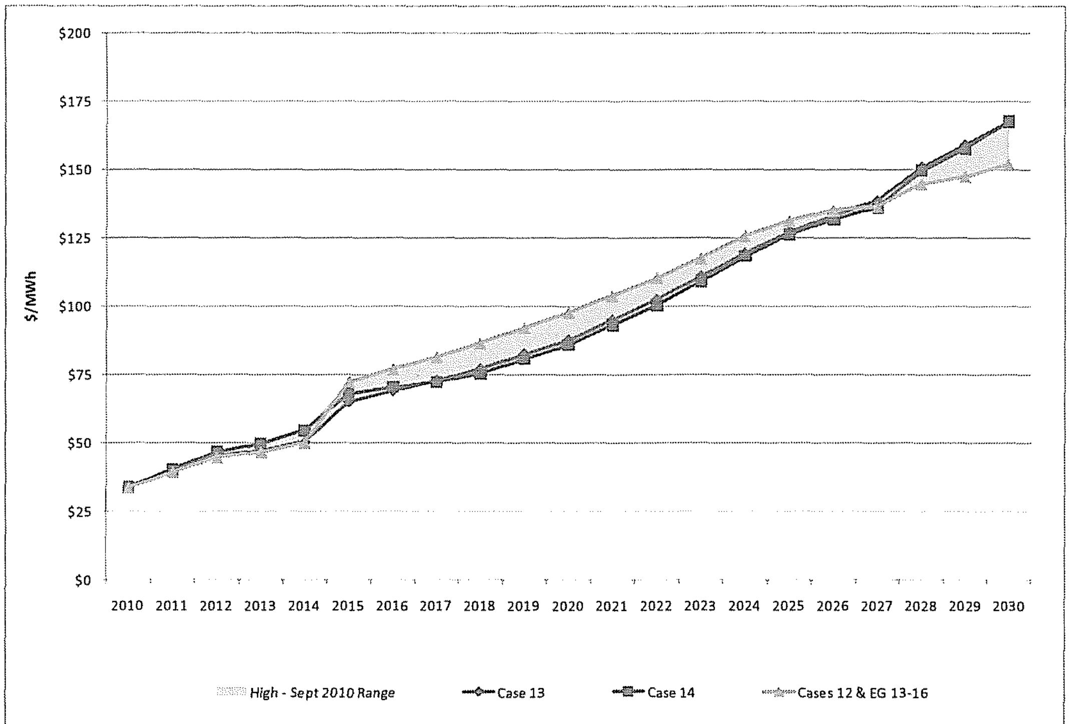


Figure 7.9 – Western Electricity Prices from the High Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Price Projections Tied to the Medium Forecast

The underlying September 2010 medium gas price forecast relies upon market forwards for the first six years and a fundamentals-based projection thereafter. For the market portion of the forecast, prices are based upon forwards as of market close on September 30, 2010. The fundamentals-based part of the forecast depicts a future in which declining LNG imports coincide with a strong demand from the electric sector driven by resistance to new coal-fired and nuclear capacity and inefficient coal plant retirements. Unconventional production, especially shale gas, is assumed to largely be able to keep pace with growing demand. Quantities of shale gas are forecasted to be higher than previously thought. Figure 7.10 shows Henry Hub benchmark prices and Figure 7.11 includes the accompanying electricity prices for the forecasts developed around the medium gas price projection.

Figure 7.10 – Henry Hub Natural Gas Prices from the Medium Underlying Forecast

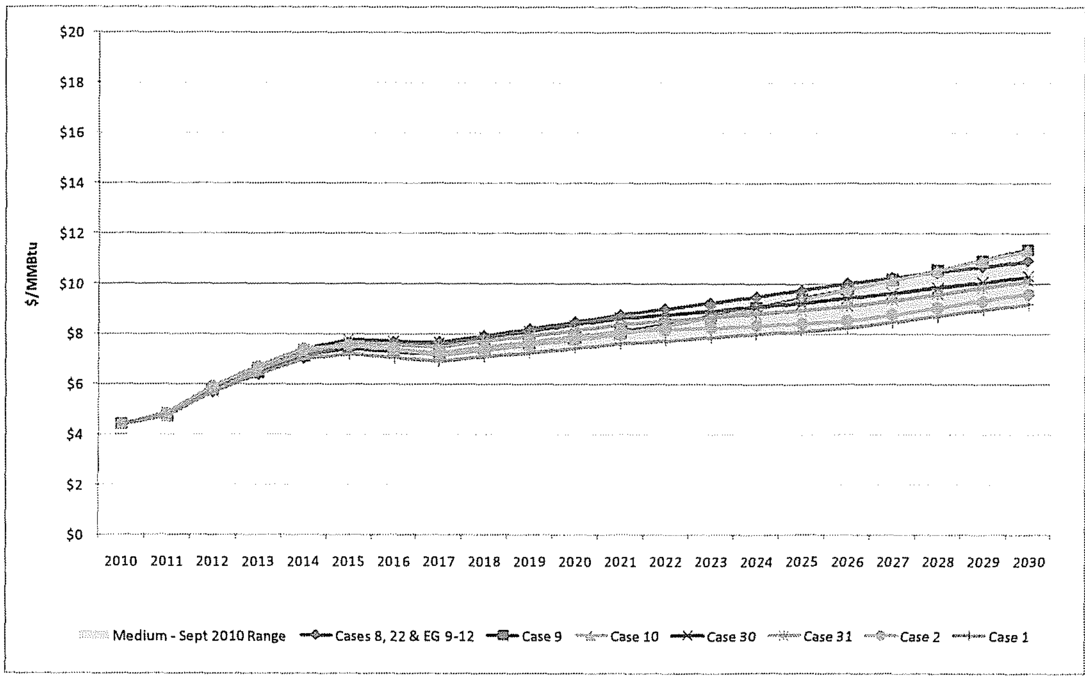
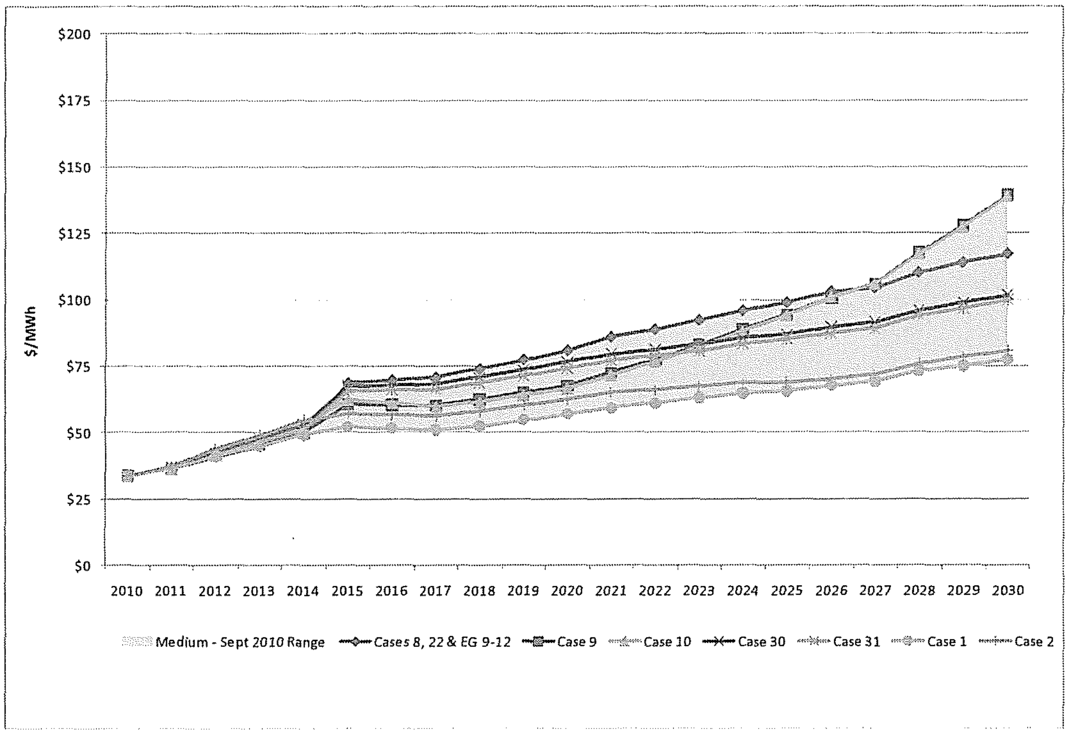


Figure 7.11 – Western Electricity Prices from the Medium Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Price Projections Tied to the Low Forecast

The underlying low gas price forecast is defined by continued growth of low-cost non-conventional gas supplies and an increase in LNG imports as weaker global economic growth drives down demand in Europe, China and elsewhere. This increase in supply, coupled with weaker demand growth, primarily in industrial and power generation sectors, results in lower gas prices that continue to support coal switching. Figure 7.12 shows Henry Hub benchmark prices and Figure 7.13 includes the accompanying electricity prices for the forecasts developed around the low gas price projection.

Figure 7.12 – Henry Hub Natural Gas Prices from the Low Underlying Forecast

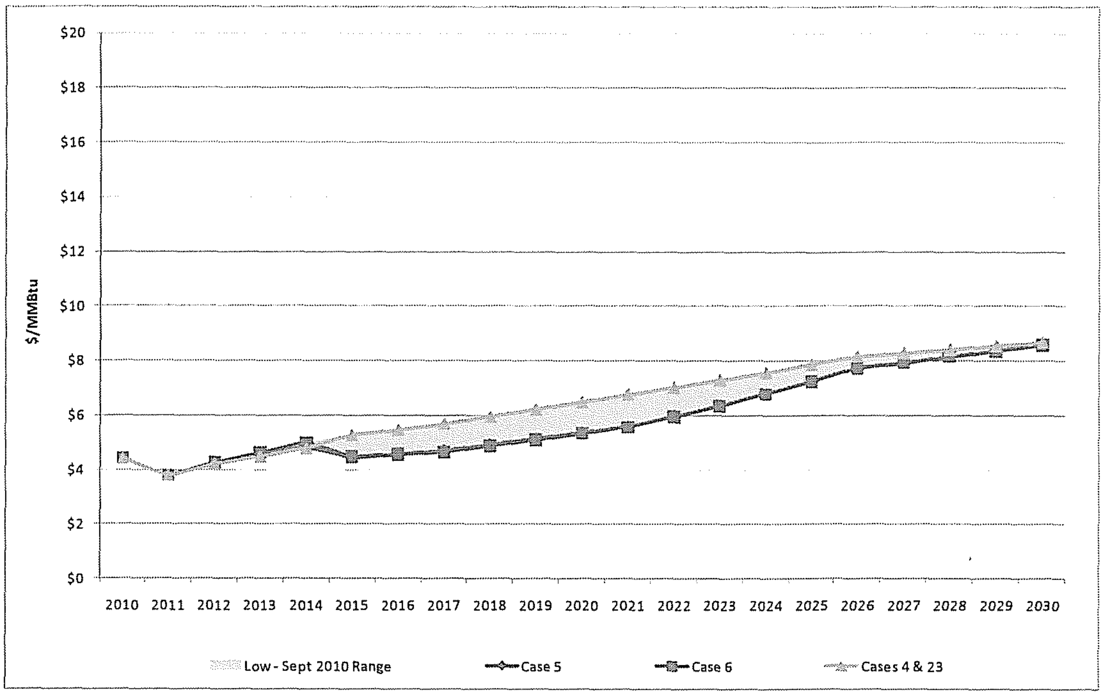
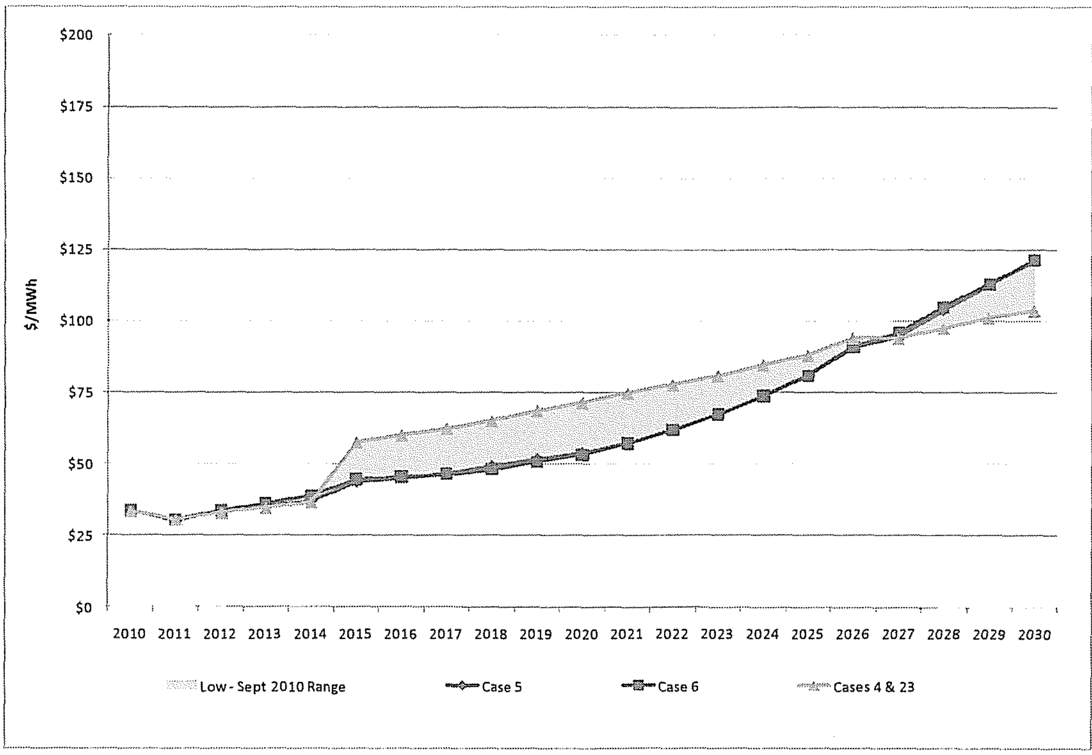


Figure 7.13 – Western Electricity Prices from the Low Underlying Gas Price Forecast



[1]Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Optimized Portfolio Development

For Phase 3, System Optimizer is executed for each set of case assumptions, generating an optimized investment plan and associated real levelized present value of revenue requirements (PVRR) for 2011 through 2030. System Optimizer operates by minimizing for each year the operating costs for existing resources subject to system load balance, reliability and other constraints. Over the 20-year study period, it also optimizes resource additions subject to resource investment and capacity constraints (monthly peak loads plus a planning reserve margin for each load area represented in the model).

To accomplish these optimization objectives, the model performs a time-of-day least-cost dispatch for existing and potential planned generation, contract, DSM, and transmission resources. The dispatch is based on a representative-week method. Time-of-day hourly blocks are simulated according to a user-specified day-type pattern representing an entire week. Each month is represented by one week, with results scaled to the number of days in the month and then the number of months in the year. The dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the overall PVRR, consisting of the net present value of contract and spot market purchase costs, generation costs (fuel, fixed and variable operation and maintenance, unserved energy, and unmet capacity), and amortized capital costs for planned resources.

For capital cost derivation, System Optimizer uses annual capital recovery factors to address end-effects issues associated with capital-intensive investments of different durations and in-service dates. PacifiCorp used the real-levelized capital costs produced by System Optimizer for portfolio cost reporting by the PaR model.

System Optimizer Customizations

PacifiCorp had its model vendor Ventyx add custom functionality to the model to improve the representation of CO_2 and renewable portfolio standards modeling. The new functionality consists of a topology overlay for defining and linking sources and sinks for tracking carbon emissions and renewable energy production. The sources represent individual generators while sinks are defined as user-specified areas typically demarcated as states or multi-state regions. The key benefit of this new functionality is the ability to assign a CO_2 emission rate to system balancing (spot market) transactions and account for such transaction activity in hard emission cap regulatory scenarios. This functionality also enables definition of CO_2 emission constraints for a specific thermal generator as it relates to one or multiple sinks. An application of this capability is to apply a state-specific emission performance standard to a coal plant, thereby limiting or preventing energy to be exported to that state. Finally, this functionality allows the model to allocate system renewable energy to individual states to meet RPS requirements.[58]

[58] This functionality does not enable the model to optimize renewable energy capacity expansion based on individual state RPS requirements. Rather, it ensures that sufficient renewable energy can be generated within a state and imported from other parts of the system to meet a state-specific RPS target. This functionality also does not account for banking rules.

For the 2011 IRP, the Company used the new functionality to model system balancing transaction emissions for the various emission hard cap scenarios described above. Initial System Optimizer modeling for the IRP yielded no new coal plants in any portfolio, so implementation of state-specific emission performance standards was deemed unnecessary.

Representation and Modeling of Renewable Portfolio Standards

PacifiCorp incorporates annual system-wide renewable generation constraints in the System Optimizer model to ensure that each optimized portfolio meets current state RPS requirements and applicable federal RPS scenarios. As noted above, for the base case RPS requirement, current Oregon, Utah, Washington, and California rules are followed. Two of the core cases assume no RPS is in place as a baseline for measuring renewable resource costs. A key assumption backing the system-wide RPS representation is that all of PacifiCorp's State jurisdictions will adopt renewable energy credit (REC) trading rules through the Multi-state Process, thus enabling sales and purchase of surplus banked RECs. System Optimizer is not designed to track or optimize REC sales, purchases, or banking balances.

Modeling Front Office Transactions and Growth Resources

Front office transactions, described in Chapter 6, are assumed to be transacted on a one-year basis, and are represented as available in each year of the study. For capacity optimization modeling, System Optimizer engages in market purchase acquisition—both front office transactions, and for hourly energy balancing, spot market purchases—to the extent it is economic given other available resources. The model can select virtually any quantity of FOT generation up to limits imposed for each case, in any study year, independently of choices in other years. However, once a front office transaction resource is selected, it is treated as a must-run resource for the duration of the transaction period. For this IRP, front office transactions are available for all years in the study period.

The front office transactions modeled in the Planning and Risk Module generally have the same characteristics as those modeled in the System Optimizer, except that transaction prices reflect wholesale forward electric market prices that are "shocked" according to a stochastic modeling process prior to simulation execution.

Another resource type included in the IRP models is the *growth resource*. This resource is intended for capacity balancing in each load area to ensure that capacity reserve margins are met in the out years of each simulation (after 2020). The System Optimizer model can select an annual flat or third-quarter HLH energy pattern priced at forward market prices appropriate for each load area. Growth resources are similar to front office transactions, except that they are not transacted at market hubs. For each market hub, they are capped at 1,000 MW on a cumulative basis for 2021-2030.

Modeling Wind Resources

As discussed in Chapter 6, PacifiCorp revised its approach for locating wind resources to match up with WREZs and facilitate assignment of incremental transmission costs for the Energy Gateway transmission scenario analysis. Wind resources are modeled as must-run units in both the System Optimizer and Planning and Risk models using hourly fixed energy shapes. Because System Optimizer is not a detailed chronological unit commitment and dispatch model, the cost impacts of wind tied to unit commitment are not captured. Also, system costs and reliability effects associated with intra-hour wind variability are not captured.

Stochastic Production Cost Adjustment for Combined-cycle Combustion Turbines

Historically, System Optimizer has undervalued CCCT resources relative to peaking gas resources. To help ensure that System Optimizer resource selection accounts for the value of flexible dispatchable resources given stochastic uncertainty, the Company estimated a capital cost credit for CCCTs using deterministic and stochastic production cost simulations.[59] The cost credit reflects the levelized net operating revenue difference between gas resources in a portfolio simulated stochastically and the same portfolio simulated deterministically. PacifiCorp selected an intercooled aeroderivative simple-cycle combustion turbine (IC aero SCCT) as the proxy peaking resource for derivation of the cost credit.

The cost credit is $179/kW in 2010 dollars, and is applied to the capital cost of all CCCT resource options in the model. Since this cost credit is only used to affect the outcome of resource selection, the credit is removed from the System Optimizer's reported PVRR as a post-modeling cost adjustment.

Modeling Fossil Fuel Efficiency Improvements

For all IRP modeling, PacifiCorp used forward-looking heat rates for existing fossil fuel plants, which account for plant efficiency improvement plans. Previously the Company used four-year historical average heat rates. This change ensures that such planned improvements are factored in the optimized portfolios and stochastic production cost simulations, in line with the goals of the PURPA fossil fuel generation efficiency standard that is part of the 2005 Energy Policy Act.

Modeling Coal Plant Utilization

The five coal plant utilization sensitivity cases are designed to investigate, as a modeling proof-of-concept, the impacts of CO_2 cost and gas price scenarios on the existing coal fleet after accounting for coal plant incremental costs. They are intended to pave the way for future refinement of the modeling approach for investigating coal plant operations. These proof-of-concept studies are not intended to draw conclusions on the disposition of individual generating units or desirability of specific strategies to respond to future regulatory developments. As noted

[59] More information on the stochastic cost adjustment approach can be found in the report for the April 28, 2010, public input meeting, available on PacifiCorp's IRP Web site.

in the Company's IRP public meetings, the lack of certainty around key cost and regulatory drivers serves as a major caveat for this study.

Table 7.9 below outlines the costs assigned to the existing coal unit and the gas plant betterment option by cost category. Note that certain costs have not been incorporated into the analysis; however, capital expenditures for planned and/or ongoing pollution control equipment investments included in the Company's business plan are incorporated whether currently committed via contract or not. In addition to best available retrofit technology (BART) requirements under the EPA's regional haze rules, increasingly more stringent National Ambient Air Quality Standards (NAAQS) have been, and are continuing to be, adopted for criteria pollutants, including SO_2, NO_2, ozone, and PM. The pollution control project costs included in the coal utilization study assist in meeting these more stringent standards, avoiding the negative consequences of an area being declared to be a nonattainment area. The Company does, however, anticipate that additional state and federal environmental laws and regulations will necessitate further investment in pollution control and environmental compliance projects, as well as further evaluation of unit specific operational/dispatch impacts, especially with respect to pending greenhouse gas regulations and hazardous air pollutants maximum achievable control technology (HAPs MACT) requirements.

Table 7.9 – Resource Costs, Existing and Associated Plant Betterment Cost Categories

Existing Coal Unit Costs	Gas Plant Betterment Option Costs
• Fixed Operations & Maintenance (O&M) • Coal fuel cost • Incremental fixed O&M - on-going capital recovery • Incremental fixed O&M – Planned comprehensive air initiative investments • Incremental comprehensive air initiative capital recovery • Incremental mining capital recovery	• Construction, $/kW • Variable and fixed O&M • Liquidated damages for not complying with minimum-take provisions of existing coal supply contracts • Existing un-depreciated coal plant • Fixed cost - natural gas pipeline expansion and transportation • Natural gas commodity cost • Decommissioning existing plant/site preparation (one time fixed O&M charge)

Costs associated with Mercury MACT compliance have been incorporated. Costs that have not been incorporated include potential plant regulatory compliance costs associated with the EPA's proposed rules for coal combustion residuals (CCR) and cooling water intake structures, as well as any transmission upgrade costs associated with replacement resource options. Such costs and operational impacts are speculative, and in the case of pending environmental rules and regulations, depend on the outcome of the respective rulemaking processes.

As a simplifying assumption, coal contract liquidated damages reflect estimated costs from 2016 to 2020 and are converted to a real levelized payment over the 20-year model simulation period. Similarly, the remaining plant balance for 2011 is converted to a real levelized payment that reflects capital recovery and depreciation over the 20-year simulation period.

Coal units are not specified with a shut-down date; in other words, the units are assumed to operate past 2030 unless the model chooses a replacement. System Optimizer is allowed to select the gas plant betterment option for any year after 2016. The existing coal unit is dispatched up to the point when the replacement resource is added.

Modeling Energy Storage Technologies

Energy storage resources in both System Optimizer and Planning and Risk (PaR) are distinguished from other resources by the following three attributes:

- energy "take" – generation or extraction of energy from a reservoir;
- energy "return" – energy used to fill (or charge) a reservoir; and
- storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

The models require specification of a reservoir size. For System Optimizer, reservoir size is defined as a megawatt capacity value, whereas in PaR it is defined in gigawatt-hours. System Optimizer dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage cycle efficiency, the daily balance of take and return energy, and fuel costs (for example, the cost of natural gas for expanding air with gas turbine expanders). To determine the least-cost resource expansion plan, the model accounts for conventional generation system performance and cost characteristics of the storage resource, including investment cost, capacity factor, heat rate (if fuel is used), O&M cost, minimum capacity, and maximum capacity.

In PaR, simulations are conducted on a week-ahead basis. The model operates the storage plant to balance generation and charging, accounting for cycle efficiency losses, in order to end the week in the same net energy position as it began. The model chooses periods to generate and return energy to minimize system cost. It does this by calculating an hourly *value of energy* for charging. This value of energy, a form of marginal cost, is used as the cost of generation for dispatch purposes, and is derived from calculations of system cost and unit commitment effects. For compressed air energy storage (CAES) plants, a heat rate is included as a parameter to capture fuel conversion efficiency. The heat rates entered in both models represent the use of PacifiCorp's off-peak coal-fired plants.

Monte Carlo Production Cost Simulation

Phase 4 entails simulation of each optimized portfolio from Phase 3 using the Planning and Risk model in stochastics mode. The PaR simulation produces a dispatch solution that accounts for chronological commitment and dispatch constraints. Three stochastic simulations were executed for the three CO_2 tax levels: none, medium – starting at $19/ton, and low to high – starting at $12/ton and escalating to $93/ton by 2030. All the simulations used the September 2010 forward price curves as the expected gas and electricity price forecast values. This maintains comparability with the price forecast assumptions used for the 2011 business plan. All the core cases, coal plant utilization cases, and the high/low economic growth cases, are simulated with the PaR model.

The PaR simulation incorporates stochastic risk in its production cost estimates by using a stochastic model and Monte Carlo random sampling of five stochastic variables: loads, commodity natural gas prices, wholesale power prices, hydro energy availability, and thermal unit availability for new resources. (For existing thermal units, planned maintenance schedules were used.[60]) Representation of wind output as a stochastic variable in PaR was ruled out because of the incremental model run-time impacts and impracticality of representing the significant intra-hour fluctuations not captured in hourly data. Although wind resource generation was not varied in the same way as the other stochastic variables, the hour-to-hour generation does vary throughout the year, but the pattern is repeated identically for all study years and Monte Carlo iterations. Note that intra-hour variability and associated incremental reserve requirements and costs are addressed in PacifiCorp's wind integration study, included as Appendix I in Volume 2.

For stochastic analysis, only the core cases (1-19), coal utilization cases (21-24[61]), and alternative load growth sensitivity cases (25-27) were modeled using the Planning and Risk production cost model. In the case of the two Utah solar buy-down sensitivity cases, 30 and 30a, it is important to note that the Utah distributed solar PV resource costs reflect assumed deep discounts to motivate significant customer program participation. Consequently, these Utah solar resources are not comparable to other resources on a cost evaluation basis. Similarly, comparison of stochastic PVRR cost measures for portfolios that include cost buy-down solar resources relative to those that do not is not meaningful and fails to meet the state IRP Standards and Guidelines provision to evaluate resources "on a consistent and comparable basis".

The Stochastic Model

The stochastic model used in PaR is a two-factor (short-run and long-run) short-run mean reverting model. Variable processes assume normality or log-normality as appropriate. Since prices and loads are bounded on the low side by zero they tend to take on a lognormal shape. Thus, prices, especially, are described as having a lognormal distribution (i.e. having a positively skewed distribution while their log_e has more of a normal distribution). Load growth is inherently more bounded on the upside than prices, and can therefore be modeled as having a normal or lognormal distribution. As such, prices and loads were treated as having a lognormal and normal distribution, respectively. Stochastic parameters may only be modeled as having a normal or lognormal distribution using PaR's integrated stochastic model.

Separate volatility and correlation parameters are used for modeling the short-run and long-run factors. The short-run process defines seasonal effects on forward variables, while the long-run factor defines random structural effects on electricity and natural gas markets and retail load regions. The short-run process is designed to capture the seasonal patterns inherent in electricity and natural gas markets and seasonal pressures on electricity demand.

[60] Stochastic simulation of existing thermal unit availability is undesirable because it introduces cost variability unassociated with the evaluation of new resources, which confounds comparative portfolio analysis.

[61] The Case 20 coal utilization portfolio (medium CO_2 tax and gas prices) did not result in any coal plant replacements, so the Company did not consider it worthwhile to conduct a stochastic production cost simulation with this portfolio.

Mean reversion represents the speed at which a disturbed variable will return to its seasonal expectation. With respect to market prices, the long-run factor should be understood as an expected equilibrium, with the Monte Carlo draws defining a possible forward equilibrium state. In the case of regional electricity loads, the Monte Carlo draws define possible forward paths for electricity demand.

Stochastic Model Parameter Estimation

Stochastic model parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. Loads and commodity prices are mean-reverting in the short term. For instance, natural gas prices are expected to "hover" around a moving average within a given month and loads are expected to hover near seasonal norms. These built-in responses are the essence of mean reversion. The mean reversion rate tells how fast a forecast will revert to its expected mean following a shock. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance.

The long run does not display mean reversion since long-run volatility is a growth rate (trend) that progresses steadily over time. Mean reversion is responsible for ultimately dampening short-run volatility into long-run volatility. The long-run parameters are derived from a "random-walk with drift" regression. The short- and long-run parameter estimations are compatible because both come from the same data but short-run volatilities are influenced by mean reversion whereas the long-run are not. The standard error of the random-walk regression defines the long-run volatility for the regional electricity load variables. However, for this IRP, the long-run load volatility parameters were turned off. The justification for this decision is described is the next section. Use of this parameter drives increasingly higher load excursions and severity of unmet energy situations (reserve deficiencies and unserved demand) as the Monte Carlo simulation progresses, and thus becomes one of the most significant portfolio cost drivers. Much of the focus for out-year portfolio modeling is to appropriately capture the end effects of near-term resource decisions reflected in the IRP action plan. Consequently, PacifiCorp believes that dropping the long-run load volatility parameters results in a more realistic comparison between portfolios.

Long-term price volatility (i.e., natural gas and electricity) is estimated using the standard error of a random walk regression of historic price data, by market. The resulting parameters are then used in PaR to develop alternative price scenarios around the Company's official forward price curves, by market, over the twenty-year IRP study period. The long-run regression errors are correlated to capture inter-variable effects from changes to expected market equilibrium for natural gas and electricity markets, as well as the impacts from changes in expected regional electricity loads.

PacifiCorp's econometric analysis is performed for the following stochastic variables:

- Fuel prices (natural gas prices for the Company's western and eastern control areas)
- Electricity market prices for Mid-Columbia (Mid C), California – Oregon Border (COB)
- Four Corners, and Palo Verde (PV)
- Electric transmission area loads (California, Idaho, Oregon, Utah, Washington and Wyoming regions)
- Hydroelectric generation

For this IRP, PacifiCorp only updated its seasonal short-term stochastic load parameters (volatilities, mean reversions, and correlations); its long-term load volatilities were set to zero. Usually, long-term load volatility can be thought of as year-on-year growth. For example, in this IRP, average annual system load growth is forecast at approximately 1.9 percent. Thus, by setting the long-term load volatilities to zero, only the expected system load growth (~1.9%) is simulated over the 20-year horizon. The decision to turn off long-term load volatilities is discussed further in the next section. Typically, for long-term planning purposes, parameter updating is only needed on an infrequent basis. However, due to changes in the model topology representation of load, coupled with the recent availability of a well-scrubbed hourly load dataset[62], the Company decided the timing was right to update load parameters.

As seen in Table 7.10 the 2011 short-term load parameters are similar in magnitude to those of the 2008 IRP. Differences are attributed to both the vintage and definition of load data used to estimate parameters. PacifiCorp estimated the 2008 parameters with 48 months of load data ending September 2005, whereas the 2011 load parameters were calculated using 36 months of calendar-year data for 2007-2009. PacifiCorp believes that three years of hourly load data is sufficient for short term stochastic volatility parameter estimation, and, as noted above, it was prudent to use the already scrubbed dataset developed for the wind integration study. Moreover, PacifiCorp estimated the 2008 parameters using jurisdictional state load data. In contrast, the 2011 parameters were estimated using hourly load data as defined by the model topology. Natural gas and electricity price correlations by delivery point, as shown in Table 7.11, are the same as those developed for the 2007 IRP.

Table 7.10 – Short Term Stochastic Parameter Comparison, 2008 IRP vs. 2011 IRP

Short-term Volatility	Idaho	Utah	Washington	West Main	Wyoming
Winter 2011 IRP	0.045	0.028	0.044	0.043	0.021
Spring 2011 IRP	0.038	0.037	0.043	0.044	0.017
Summer 2011 IRP	0.040	0.040	0.051	0.041	0.017
Fall 2011 IRP	0.040	0.036	0.046	0.042	0.019
Winter 2008 IRP	0.041	0.026	0.051	0.041	0.025
Spring 2008 IRP	0.051	0.028	0.038	0.032	0.022
Summer 2008 IRP	0.054	0.045	0.053	0.038	0.019
Fall 2008 IRP	0.046	0.036	0.040	0.043	0.019

[62] As prepared for PacifiCorp's 2010 wind integration study and based on actual load data for 2007 – 2009.

Short-term Mean Reversion	Idaho	Utah	Washington	West Main	Wyoming
Winter 2011 IRP	0.19	0.10	0.18	0.16	0.07
Spring 2011 IRP	0.02	0.16	0.24	0.21	0.10
Summer 2011 IRP	0.02	0.10	0.24	0.20	0.07
Fall 2011 IRP	0.03	0.08	0.11	0.11	0.05
Winter 2008 IRP	0.27	0.23	0.24	0.26	0.13
Spring 2008 IRP	0.05	0.09	0.19	0.16	0.10
Summer 2008 IRP	0.08	0.14	0.23	0.28	0.08
Fall 2008 IRP	0.23	0.17	0.20	0.18	0.10

Table 7.11 – Price Correlations

Winter						
	Nat Gas - East	Four Corners	COB	Mid Columbia	Palo Verde	Nat Gas - West
Nat Gas - East	1.000	0.304	0.386	0.277	0.371	0.835
Four Corners	0.304	1.000	0.592	0.784	0.817	0.299
COB	0.386	0.592	1.000	0.634	0.564	0.492
Mid Columbia	0.277	0.784	0.634	1.000	0.811	0.312
Palo Verde	0.371	0.817	0.564	0.811	1.000	0.364
Nat Gas - West	0.835	0.299	0.492	0.312	0.364	1.000

Spring						
	Nat Gas - East	Four Corners	COB	Mid Columbia	Palo Verde	Nat Gas - West
Nat Gas - East	1.000	0.085	0.034	(0.131)	0.105	0.281
Four Corners	0.085	1.000	0.559	0.459	0.787	0.025
COB	0.034	0.559	1.000	0.770	0.468	0.067
Mid Columbia	(0.131)	0.459	0.770	1.000	0.540	(0.059)
Palo Verde	0.105	0.787	0.468	0.540	1.000	(0.035)
Nat Gas - West	0.281	0.025	0.067	(0.059)	(0.035)	1.000

Summer						
	Nat Gas - East	Four Corners	COB	Mid Columbia	Palo Verde	Nat Gas - West
Nat Gas - East	1.000	0.115	0.074	0.002	0.101	0.908
Four Corners	0.115	1.000	0.705	0.699	0.917	0.132
COB	0.074	0.705	1.000	0.809	0.734	0.117
Mid Columbia	0.002	0.699	0.809	1.000	0.696	0.013
Palo Verde	0.101	0.917	0.734	0.696	1.000	0.126
Nat Gas - West	0.908	0.132	0.117	0.013	0.126	1.000

Fall						
	Nat Gas - East	Four Corners	COB	Mid Columbia	Palo Verde	Nat Gas - West
Nat Gas - East	1.000	0.156	0.233	0.142	0.182	0.795
Four Corners	0.156	1.000	0.458	0.719	0.921	0.244
COB	0.233	0.458	1.000	0.446	0.467	0.299
Mid Columbia	0.142	0.719	0.446	1.000	0.740	0.160
Palo Verde	0.182	0.921	0.467	0.740	1.000	0.281
Nat Gas - West	0.795	0.244	0.299	0.160	0.281	1.000

For outage modeling, PacifiCorp relies on the PaR model's Convergent Monte Carlo simulation method to create a distributed outage pattern for new resources. PacifiCorp does not estimate stochastic parameters for plant outages. Due to the true randomness of forced outages the Convergent Monte Carlo is the preferred mode of operation for obtaining results of multi-iteration Monte Carlo quality. While average historical and/or technology-specific outage rates are specified by the user the timing and duration of outages is random. The Convergent Monte Carlo produces fully converged results by rejecting highly unlikely outage combinations in peak and off-peak hours. As such, it takes fewer iterations and less time to produce robust results.

In its 2008 IRP acknowledgment order, the Public Service Commission of Utah requested that the Company address the "number of years relied upon for stochastic parameter estimation."[63]

PacifiCorp performed a literature search on stochastic electricity price forecasting models to glean information on time series sampling periods used for parameter estimation. The time periods selected varied from one year to six years depending on the pricing process, time resolution, and electricity markets studied. A key factor driving the sampling period was a long enough time series to capture seasonal and mean reversion patterns. For forecasting models based on hourly to daily time scales, the most common sampling periods were two to four years. These sampling periods are in line with PacifiCorp's parameter estimation methodology.

Monte Carlo Simulation

During model execution, PaR makes time-path-dependent Monte Carlo draws for each stochastic variable based on the input parameters. The Monte Carlo draws are of percentage deviations from the expected forward value of the variables, and are the same for each Monte Carlo simulation. In the case of natural gas prices, electricity prices, and regional loads, PaR applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

The PaR model is configured to conduct 100 Monte Carlo simulation runs for the 20-year study period, so that each of the 100 simulations has its own set of stochastic parameters and shocked forecast values. The end result of the Monte Carlo simulation is 100 production cost runs (iterations) reflecting a wide range of portfolio cost outcomes.

Unlike the 2008 IRP, the long-term load volatility parameters for the 2011 IRP are set to zero. PacifiCorp believes this is an improvement to its past stochastic treatment of loads. Key drivers tend to fall into temporal classifications of short-, medium-, and long-term. Respective classifications are not confined to convenient time periods but generally can be thought of as spanning days, months, and years. Table 7.12 summarizes the key drivers with respect to their temporal classifications.

[63] Public Service Commission of Utah, Report and Order, PacifiCorp 2008 Integrated Resource Plan, Docket No. 09-2035-01, p. 38-39.

Table 7.12 – Load Drivers by Time Period

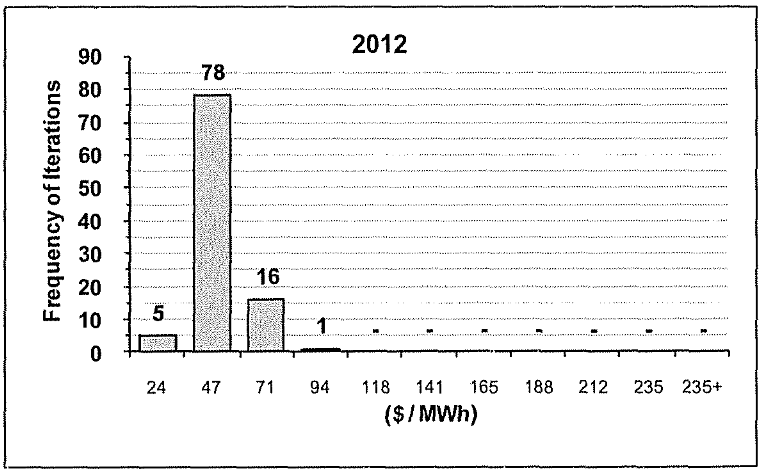
Short-term Load Drivers	Medium-term Load Drivers	Long-term Load Drivers
Weather	Seasonal	New Technologies/End Uses
Time of Day	Commodity Prices	Demographics
Load Management	Economic Growth	Fuel Switching
Day of Week		Demand Side Management
		Economic Growth

As previously discussed, PaR generates 100 Monte Carlo simulations on natural gas prices, electricity prices, regional loads, and hydroelectric generation. PaR optimizes electricity prices subject to operating and physical constraints, one of which is a fixed capacity expansion plan. That is, PaR solves for the most efficient solution subject to a given capacity plan. For short- and medium-term shocks this is not problematic since capacity is assumed to be fixed anyway and PaR simply responds to shocks by re-dispatching.

The underlying causes of long-term load changes are fundamental shifts in: technology (e.g., electric cars); demographics (e.g., population); fuel switching (e.g., switching from gasoline engines to electric motors); DSM (e.g., energy efficiency, appliance standards); and economic growth. These long-term shifts require a solution that allows capacity change. But, PaR cannot re-optimize its capacity additions, which creates a problem when dispatching to meet the more extreme load excursions often seen in long-term stochastic modeling. Since capacity is not fixed in the long term, this constraint yields an inefficient static solution. Additionally, several public stakeholders have raised concerns regarding out-year resource impacts on near-term resource selection and investment for capacity expansion modeling using System Optimizer. Large load excursions in the out years, driven by the long-term load volatility parameter, represent a parallel example of out-year resource influence on portfolio cost. These observations, coupled with the fact that loads are, by nature, somewhat bounded in the upper tail, led PacifiCorp, in consultation with its model vendor, Ventyx, to refine the stochastic modeling process by setting long-term load volatilities to zero. Note: only long-term load volatilities were affected; long-term price volatilities were not set to zero.

Figures 7.14 through 7.17 show the 100-iteration frequencies for market prices resulting from the Monte Carlo draws for two representative years, 2012 and 2020. Note that Monte Carlo draws are the same for all core case portfolios simulated with the PaR model, since only the medium electricity and gas price forecasts are used. Figures 7.18 through 7.23 show annual loads (by system and load area) for the first, tenth, twenty-fifth, fiftieth, seventy-fifth, ninetieth, and ninety-ninth percentiles. For illustrative purposes, system load frequencies were also generated incorporating the long-term load volatilities from PacifiCorp's 2008 IRP. The results are shown in FigureFigure 7.25 shows the 25th, 50th, and 75th percentiles for hydroelectric generation.

Figure 7.14 – Frequency of Western (Mid-Columbia) Electricity Market Prices for 2012 and 2020



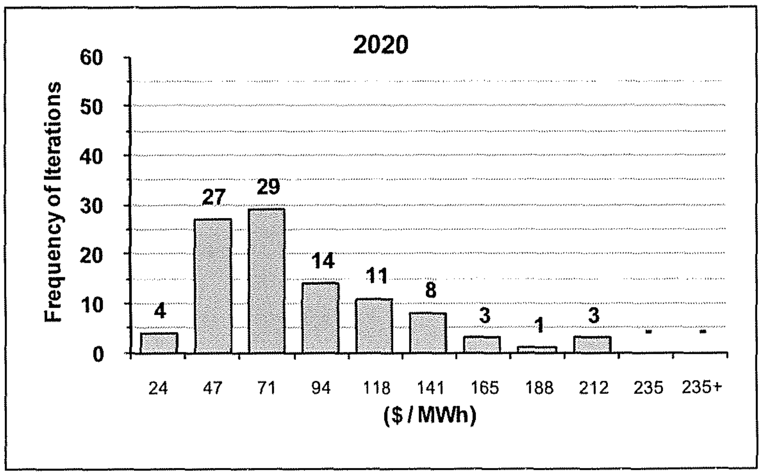
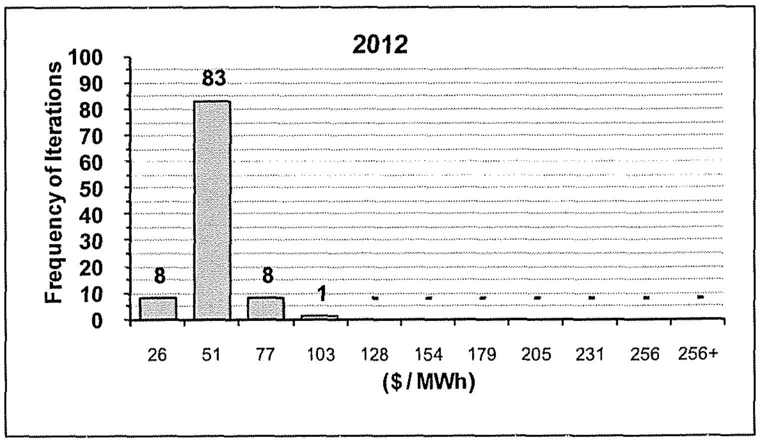


Figure 7.15 – Frequency of Eastern (Palo Verde) Electricity Market Prices, 2012 and 2020



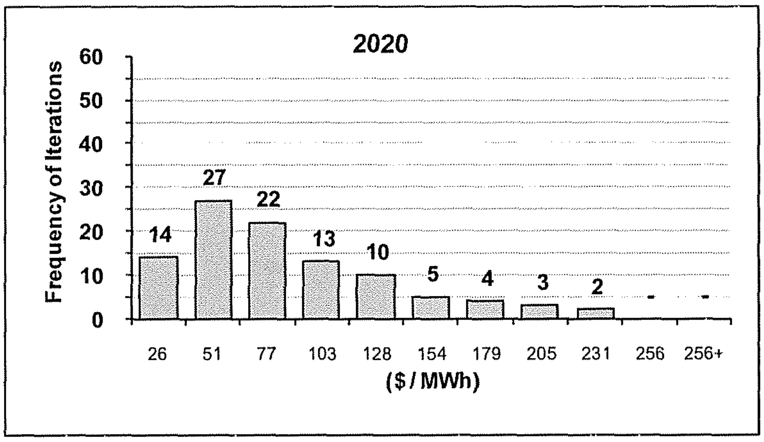
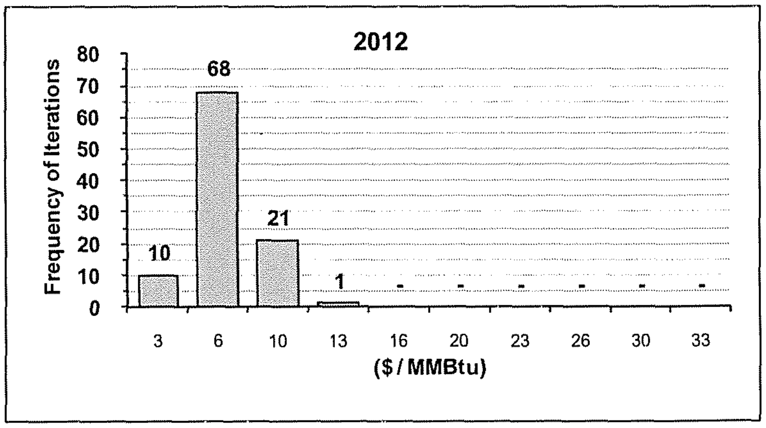


Figure 7.16 – Frequency of Western Natural Gas Market Prices, 2012 and 2020



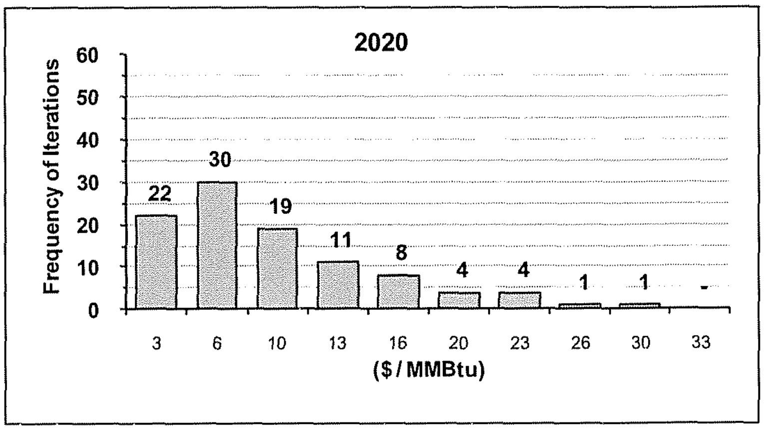
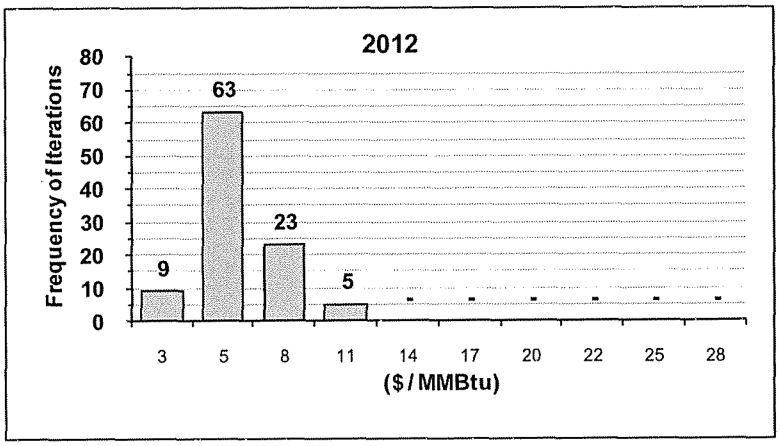


Figure 7.17 – Frequency of Eastern Natural Gas Market Prices, 2012 and 2020



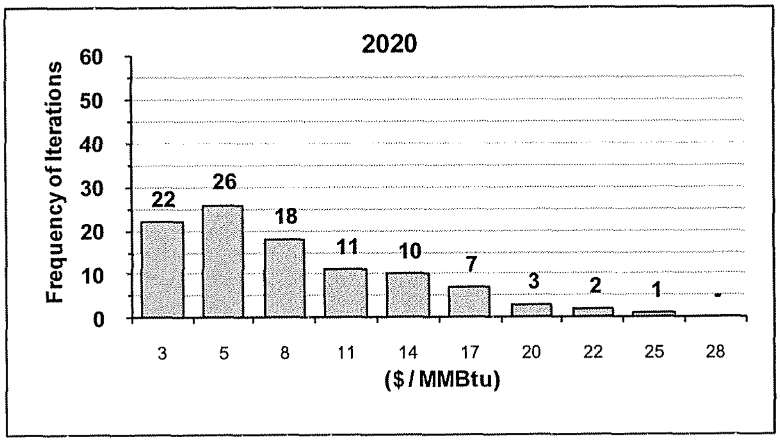


Figure 7.18 – Frequencies for Idaho (Goshen) Loads

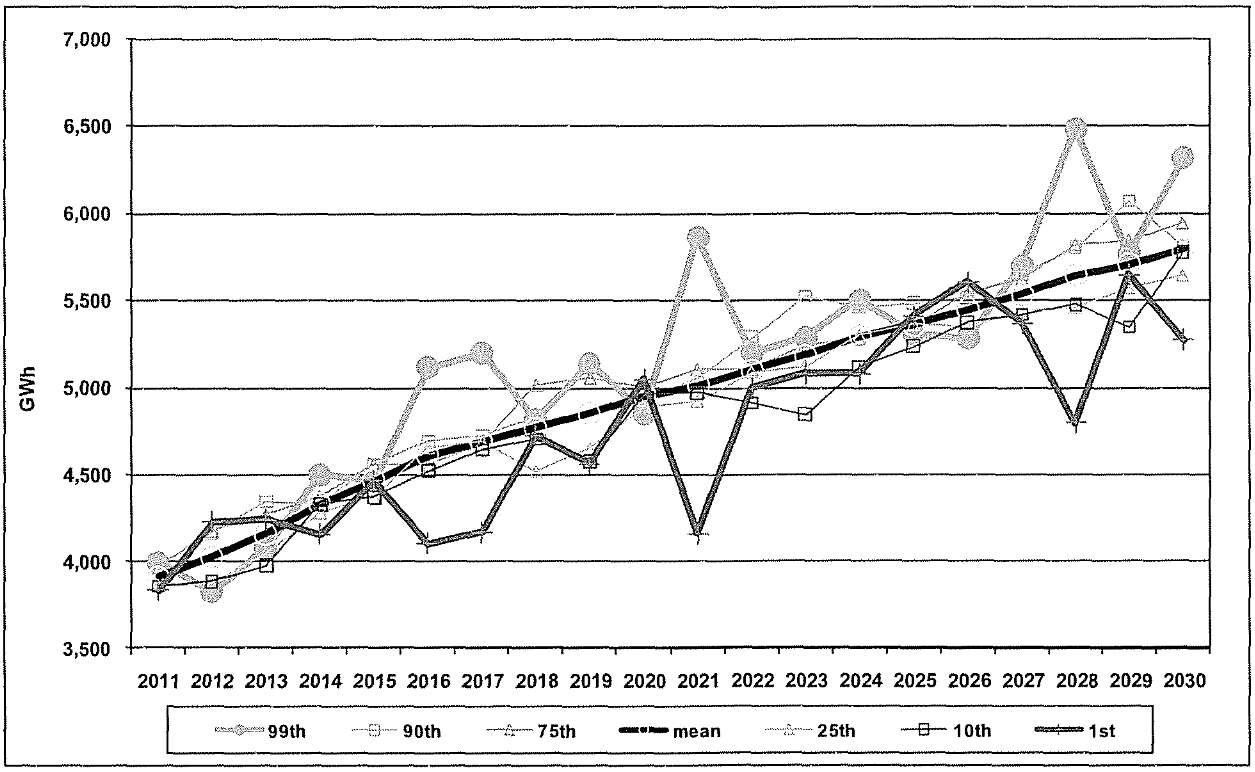


Figure 7.19 – Frequencies for Utah Loads

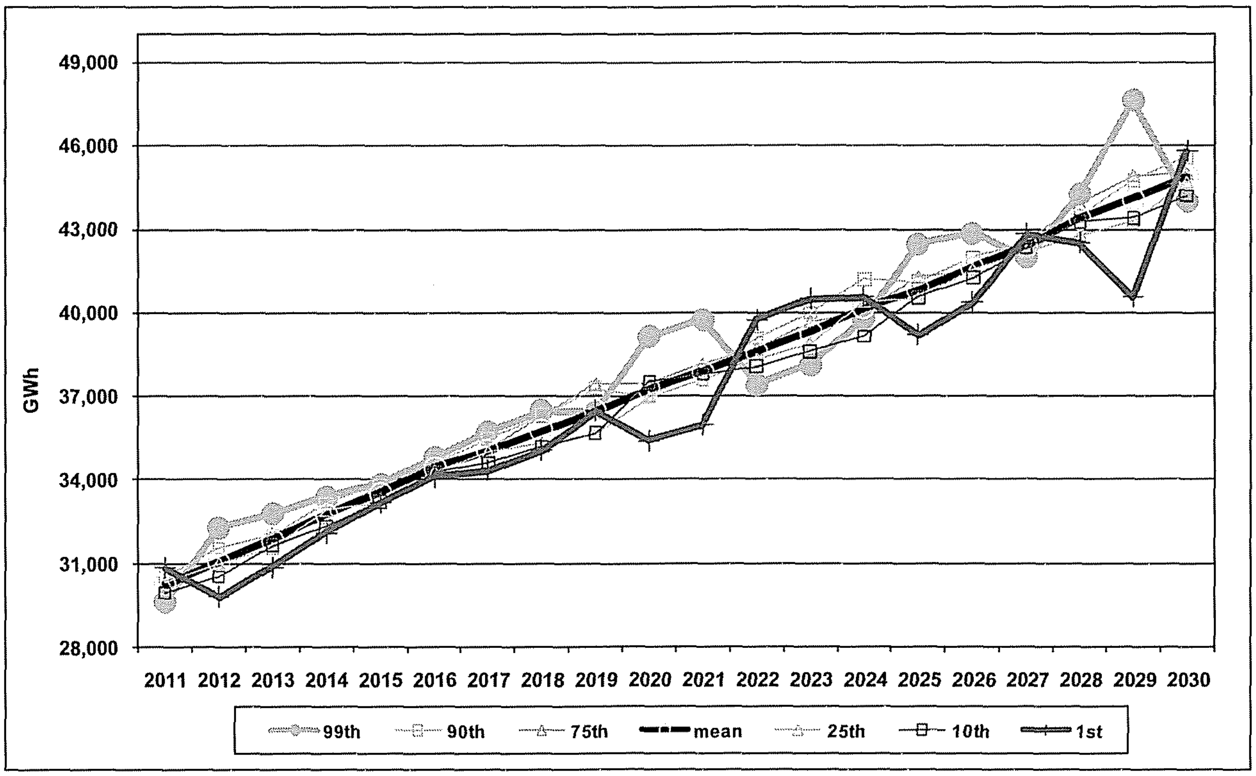


Figure 7.20 – Frequencies for Washington Loads

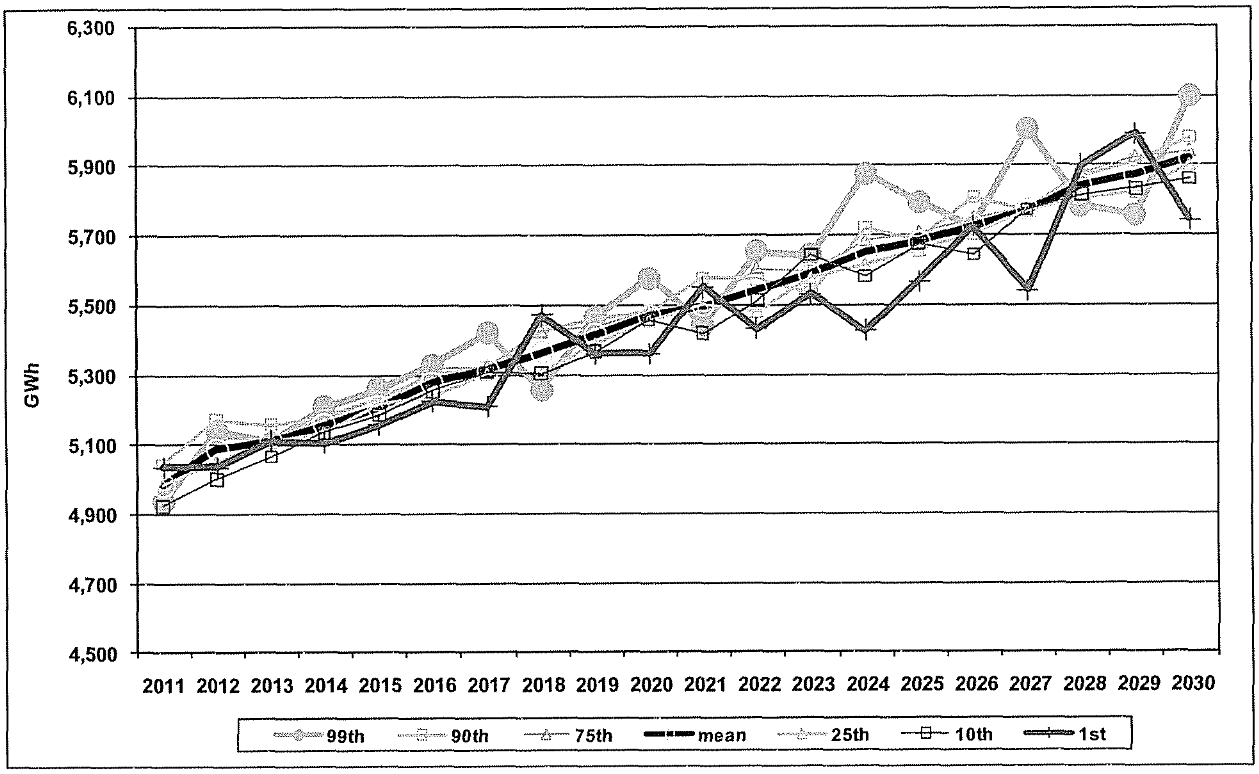


Figure 7.21 – Frequencies for California and Oregon Loads

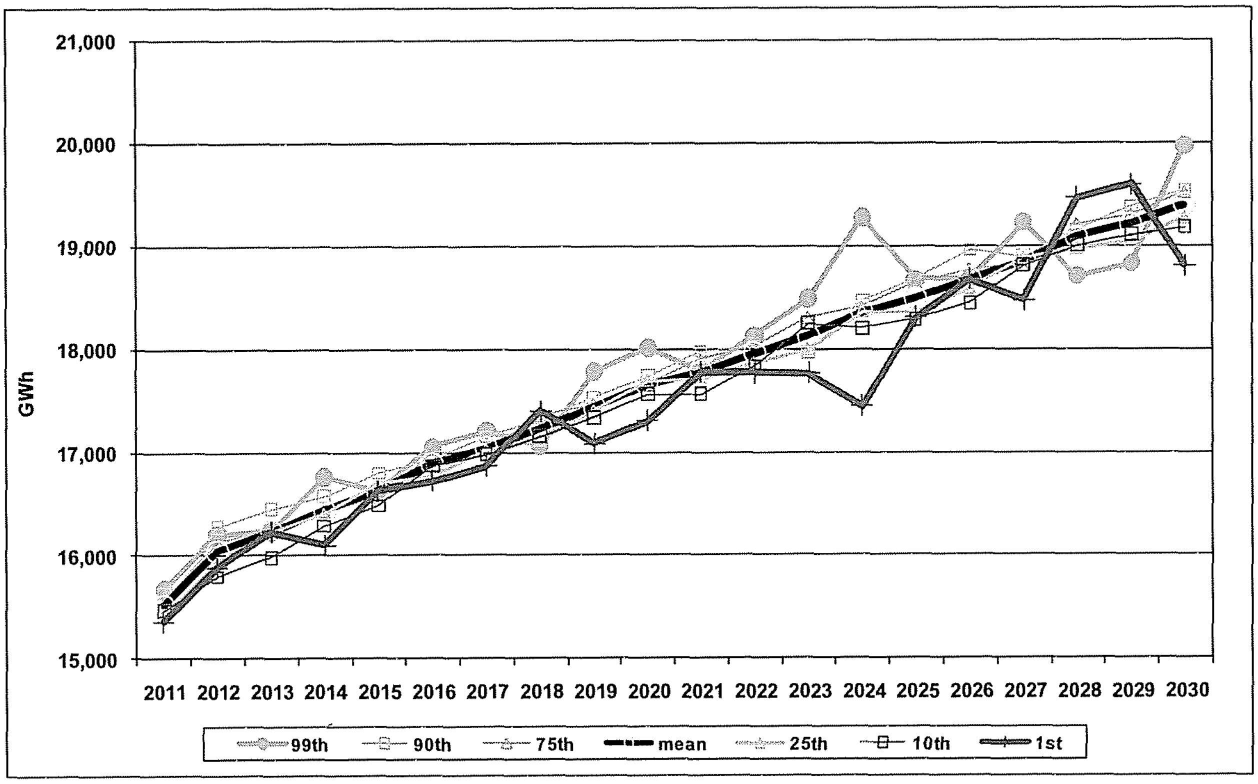


Figure 7.22 – Frequencies for Wyoming Loads

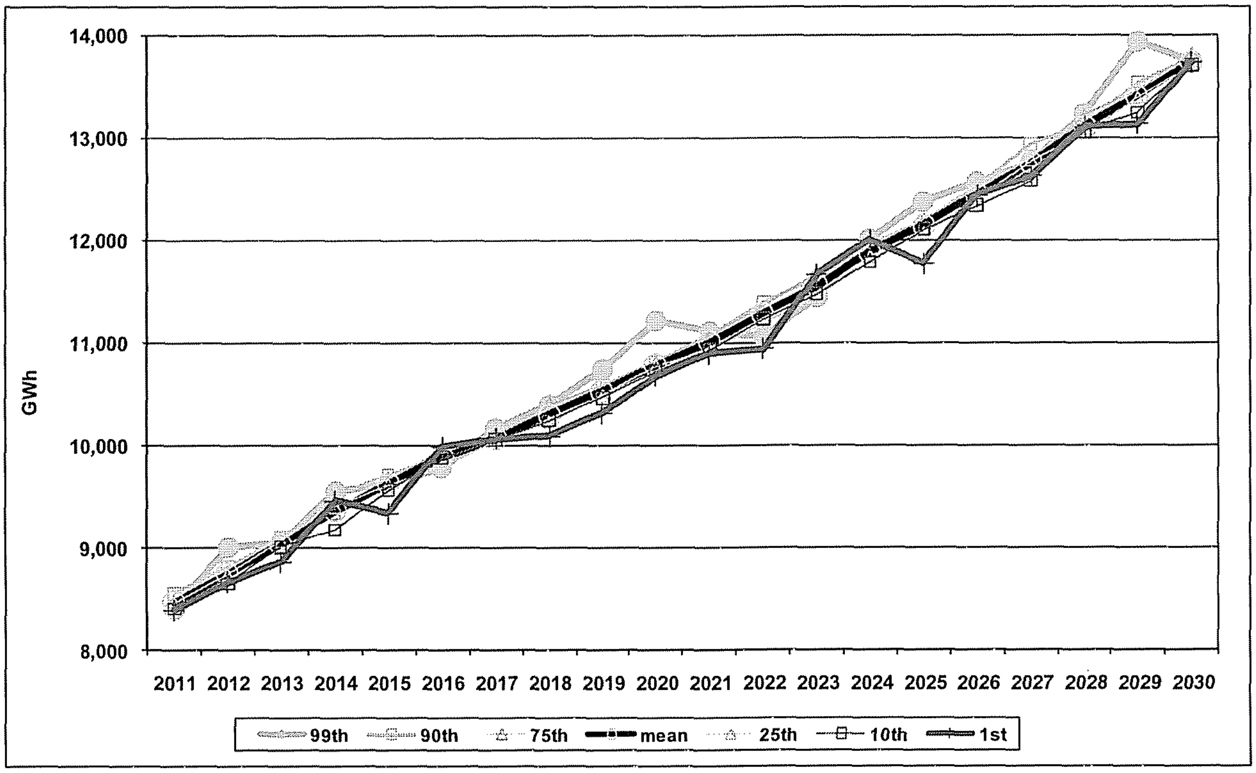


Figure 7.23 – Frequencies for System Loads

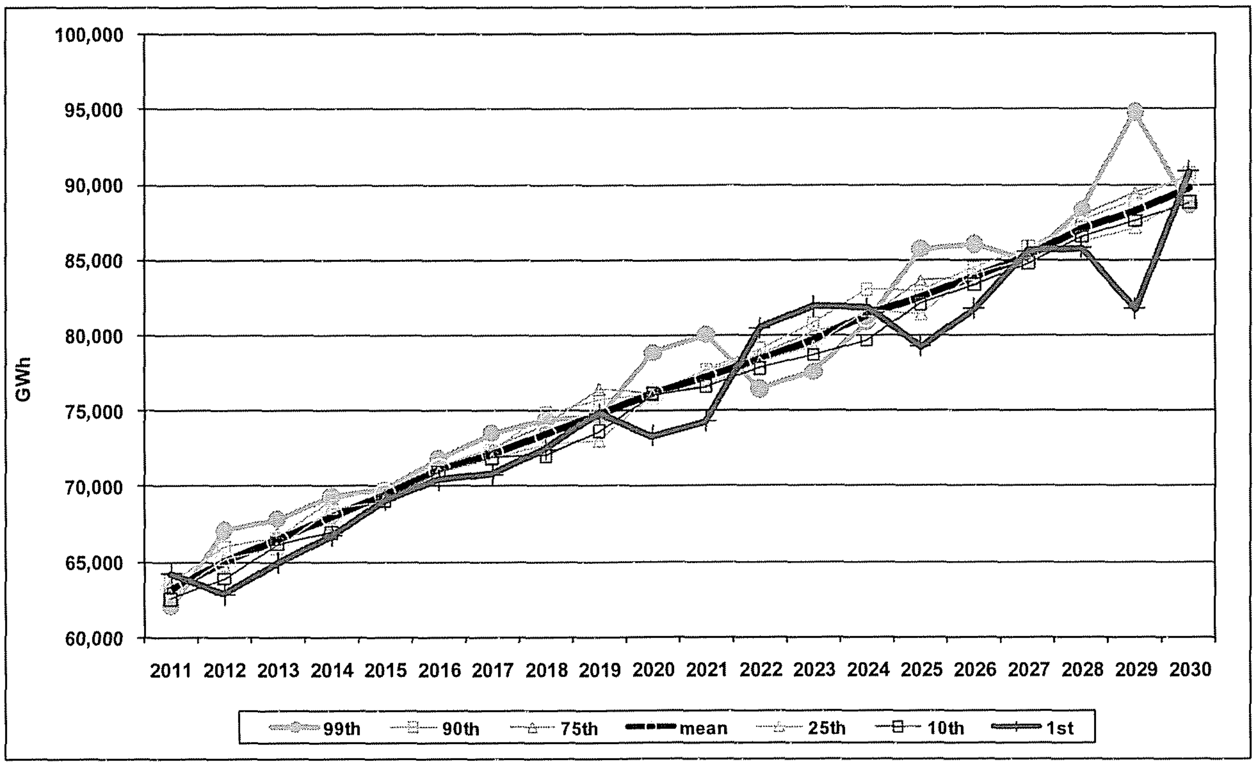


Figure 7.24 – Frequencies for System Loads (with long-term volatility)

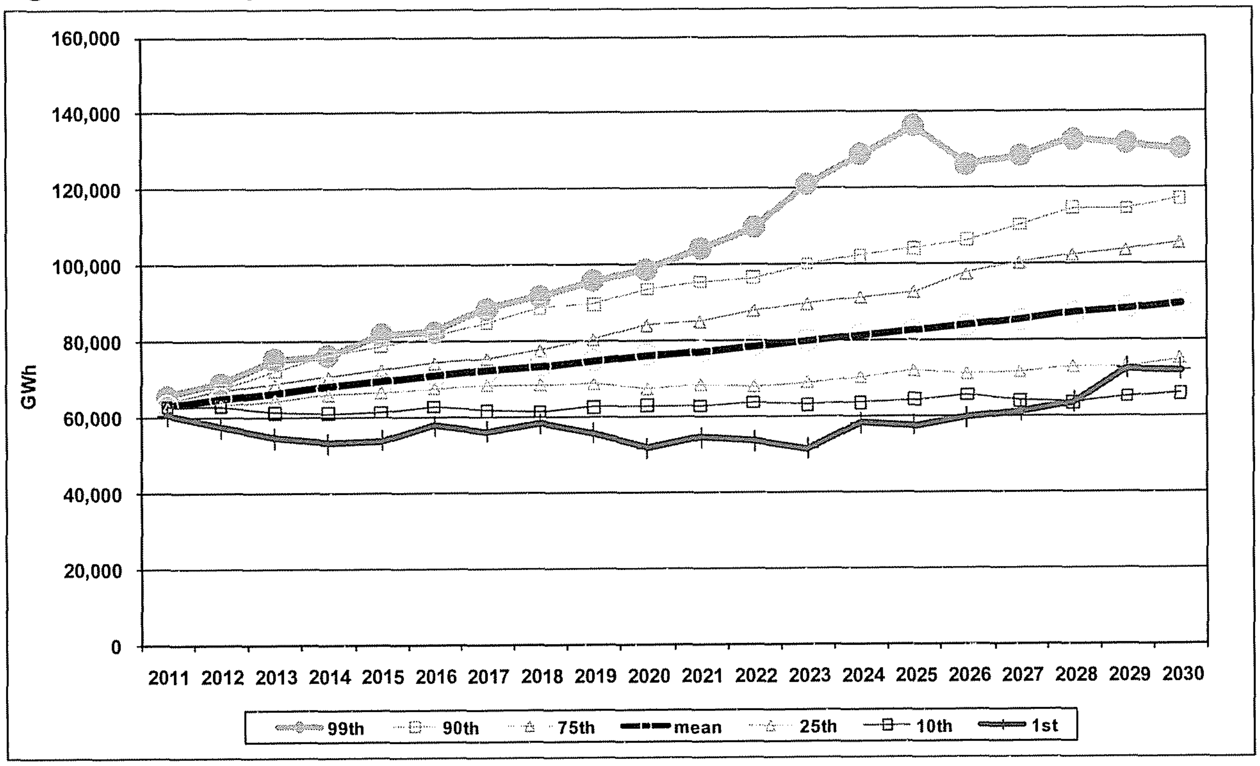
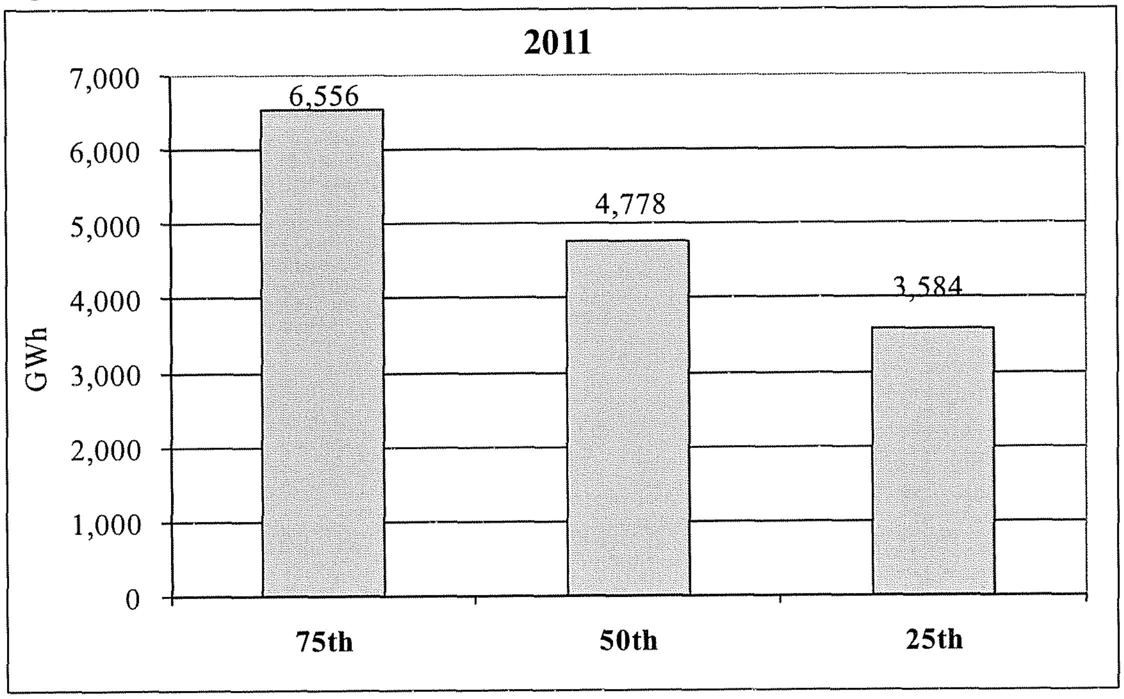
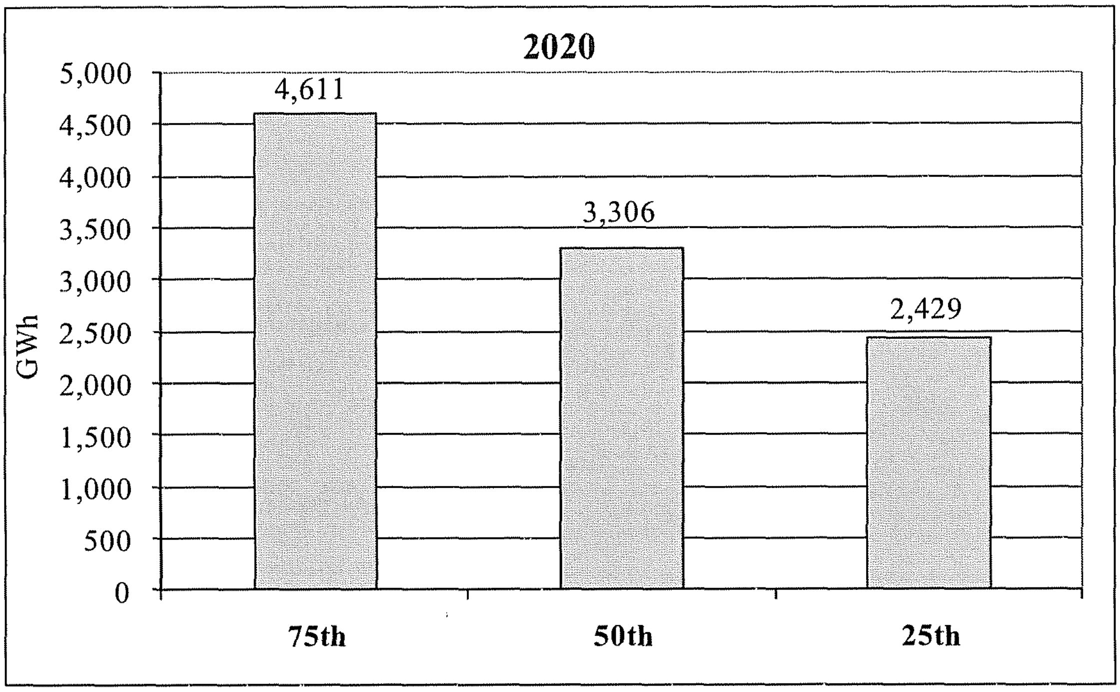


Figure 7.25 – Hydroelectric Generation Frequency, 2011 and 2020





PacifiCorp derives expected values for the Monte Carlo simulation by averaging run results across all 100 iterations. The Company also looks at subsets of the 100 iterations that signify particularly adverse cost conditions, and derives associated cost measures as indicators of high-end portfolio risk. These cost measures, and others used to assess portfolio performance, are described in the next section.

Stochastic Portfolio Performance Measures

Stochastic simulation results for the optimized portfolios are summarized and compared to determine which portfolios perform best according to a set of performance measures. These measures, grouped by category, include the following:

Cost
- Mean PVRR (Present Value of Revenue Requirements)
- Risk-adjusted mean PVRR
- 10-year customer rate impact

Risk
- Upper-tail Mean PVRR
- 5^{th} and 95^{th} Percentile PVRR
- Production cost standard deviation

Supply Reliability
- Average annual Energy Not Served (ENS)
- Upper-tail ENS
- Loss of Load Probability (LOLP)

In addition to these stochastic measures, PacifiCorp reports fuel source diversity statistics and the emission footprint of each portfolio.

The following sections describe in detail each of these performance measures as well as the fuel source diversity statistics.

Mean PVRR

The stochastic mean PVRR for each portfolio is the average of the portfolio's net variable operating costs for 100 iterations of the PaR model in stochastic mode, combined with the real levelized capital costs for new resources determined by the System Optimizer model. The PVRR is reported in 2010 dollars.

The net variable cost from the PaR simulations, expressed as a net present value, includes system costs for fuel, variable plant O&M, unit start-up, market contracts, spot market purchases and sales, and costs associated with making up for generation deficiencies (Energy Not Served and reserve deficiency costs; see the section on ENS below for background on ENS.) The variable costs included are not only for new resources but existing system operations as well. The capital additions for new resources (both generation and transmission) are calculated on an escalated "real-levelized" basis to appropriately handle investment end effects. Other components in the stochastic mean PVRR include renewable production tax credits and emission externality costs, such as a CO_2 tax.

The PVRR measure captures the total resource cost for each portfolio, including externality costs in the form of CO_2 cost adders. Total resource cost includes all the costs to the utility and customer for the variable portion of total system operations and the capital requirements for new supply and Class 1 demand-side resources as evaluated in this IRP.

A refinement to stochastic PVRR reporting for this IRP is to identify the portion of the PVRR contributed by stochastic *unmet energy costs*. This term refers to the sum of reserve deficiency costs and Energy Not Served (ENS) costs. Reserve deficiencies are priced at $500/MWh, a high penalty value that incents the model to minimize dipping below operating reserve requirements specified in the model. (The model accounts for WECC operating reserves, regulation reserves, and operating reserves held for wind integration.) Energy Not Served, described in more detail below, is a condition where there is insufficient generation available to meet load. A price is also assigned to unserved load, reflecting the marginal cost of avoiding it.

Risk-adjusted Mean PVRR

Unlike a simple mean PVRR, the risk-adjusted PVRR also incorporates the expected-value cost of low-probability, expensive outcomes.[64] This measure—risk-adjusted PVRR for short—is calculated as the stochastic mean PVRR plus the expected value, EV, of the 95th percentile production cost PVRR, where EV = $PVRR_{95}$ x 5%. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on the 100 Monte Carlo simulations conducted for each production cost run. For past IRPs,

[64] Prices are assumed to take on a lognormal distribution for stochastic Monte Carlo sampling, since they are bounded on the low side by zero and are theoretically unbounded on the up side, exhibiting a skewed distribution.

PacifiCorp's public stakeholders have indicated that avoiding expensive outcomes (upper-tail risk) should be the key risk metric for portfolio cost evaluation.

The rationale behind the risk-adjusted PVRR is to have a consolidated stochastic cost indicator for portfolio ranking, combining expected cost and high-end cost risk concepts without eliciting and applying subjective weights that express the utility of trading one cost attribute for another.

Ten-year Customer Rate Impact

For this IRP, the Company has adopted a "full revenue requirements" approach for reporting year by year and cumulative incremental portfolio rate impacts for 2011 through 2020.

To derive the rate impact measures, the Company computes the percentage revenue requirement increase (annual and cumulative 10-year basis) attributable to the resource portfolio relative to a baseline full revenue requirements forecast. These revenue requirement figures are then divided by the retail sales forecast assumed for the 2011 business plan to derive the dollars-per-MWh rate impacts. The source for the full revenue requirements is the latest baseline forecast prepared for the Multistate Process (MSP).

The IRP portfolio revenue requirement is based on the stochastic production cost results and capital costs reported for the portfolio by the System Optimizer model. Costs include variable costs, DSM program costs, existing station fixed costs, and new resource fixed and capital recovery costs.[65] The focus of the rate impact review will be on the stability of year-to-year percentage full revenue requirement impacts, as well as the cumulative 10-year total impact.

While this approach provides a reasonable representation of projected total system revenue requirements for IRP portfolio comparison purposes, it is not intended as an accurate depiction of such revenue requirements for rate-making purposes. For example, the IRP revenue impacts assume immediate ratemaking treatment and make no distinction between current or proposed multi-jurisdictional allocation methodologies.

Upper-Tail Mean PVRR

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the five highest production costs on a net present value basis. The portfolio's real levelized fixed costs are added to these five production costs, and the arithmetic average of the resulting PVRRs is computed.

95th and 5th Percentile PVRR

The fifth and ninety-fifth percentile stochastic PVRRs are also reported. These PVRR values correspond to the iteration out of the 100 that represents the fifth and ninety-fifth percentiles on the basis of production costs (net present value basis), respectively. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described

[65] New IRP resource capital costs are represented in 2010 dollars and grow with inflation, and start in the year the resource is added. This method is used so resources having different lives can be evaluated on a comparable basis. The customer rate impacts will be lower in the early years and higher in the later years when compared to customer rate impacts computed under a rate-making formula.

above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted PVRR measure. The 5th percentile PVRR is included for informational purposes.

Production Cost Standard Deviation
To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost for the 100 Monte Carlo simulation iterations. The production cost is expressed as a net present value for the annual costs for 2011 through 2030. This measure is included because Oregon IRP guidelines require a stochastic measure that addresses the variability of costs in addition to one that measures the severity of bad outcomes.

Average and Upper-Tail Energy Not Served
Certain iterations of a PaR stochastic simulation will have "energy not served" or ENS.[66] Energy Not Served is a condition where there is insufficient generation available to meet load because of physical constraints or market conditions. This occurs when the iteration has one or more stochastic variables with large random shocks that prevent the model from fully balancing the system for the simulated hour. Typically large load shocks and simultaneous unplanned plant outages are implicated in ENS events. (Deterministic PaR simulations do not experience ENS because there is no random behavior of model parameters; for example, loads increase in a smooth fashion over time.) Consequently, ENS, when averaged across all 100 iterations, serves as a measure of the stochastic reliability risk for a portfolio's resources.

For reporting of the ENS statistics, PacifiCorp calculates an average annual value for 2011 through 2030 in Gigawatt-hours, as well as the upper-tail ENS (average of the five iterations with the highest ENS). Results using the \$19/ton CO_2 tax scenario are reported, as the tax level does not have a material influence on ENS amounts.

For valuing ENS, PacifiCorp recognizes that, in practice, the planning response to significant ENS is different for short-run versus long-run ENS expectations. In the short-run, the Company would have recourse to few remedial options, and would expect to pay a large premium for emergency power. On the other hand, the Company has more planning options with which to respond to long-term forecasted ENS growth, including acquisition of peaking resources. Consequently, a tiered pricing scheme has been applied to ENS quantities generated by the Planning and Risk model. The ENS cost is set to \$400/MWh (real dollars) for the first 50 GWh/yr of ENS, \$200/MWh for the next 100 GWh/yr, and \$100/MWh for all quantities above 150 GWh/yr. For large forecasted ENS quantities that occur in the out years of the study period, the acquisition of peaking generation would become cost-effective, with the \$100/MWh reflecting the long-run all-in cost for such generation.

Loss of Load Probability
Loss of Load Probability is a term used to describe the probability that the combinations of online and available energy resources cannot supply sufficient generation to serve the load peak during a given interval of time.

For reporting LOLP, PacifiCorp calculates the probability of ENS events, where the magnitude of the ENS exceeds given threshold levels. PacifiCorp is strongly interconnected with the

[66] Also referred to as Expected Unserved Energy, or EUE.

regional network; therefore, only events that occur at the time of the regional peak are the ones likely to have significant consequences. Of those events, small shortfalls are likely to be resolved with a quick (though expensive) purchase. In Chapter 8, the proportion of iterations with ENS events in July exceeding selected threshold levels are reported for each optimized portfolio simulated with the PaR model. The LOLP is reported as a study average as well as year-by-year results for an example threshold level of 25,000 MWh. This threshold methodology follows the lead of the Pacific Northwest Resource Adequacy Forum, which reports the probability of a "significant event" occurring the winter season.

Fuel Source Diversity

For assessing fuel source diversity on a summary basis for each portfolio, PacifiCorp calculated the new resource generation shares for three resource categories as reflected in the System Optimizer expansion plan:

- Thermal
- Renewables
- Demand-side management

The shares were calculated from the generation for 2020 by resource category. Since the resource mix beyond 2020 is heavily influenced by the addition of generic growth resources, generation shares for these years are not particularly useful.

Top-Performing Portfolio Selection

Initial Screening

As noted earlier, PacifiCorp conducted stochastic simulations of all the core cases, along with the coal plant utilization cases and the high/low economic growth cases (a total of 26 portfolios). For preferred portfolio selection, the Company focused on stochastic performance of the 19 core cases. For initial screening, PacifiCorp applied the following decision rule for identifying portfolios with the best combination of lowest mean PVRR and lowest upper-tail mean PVRR.

For each CO_2 tax scenario:

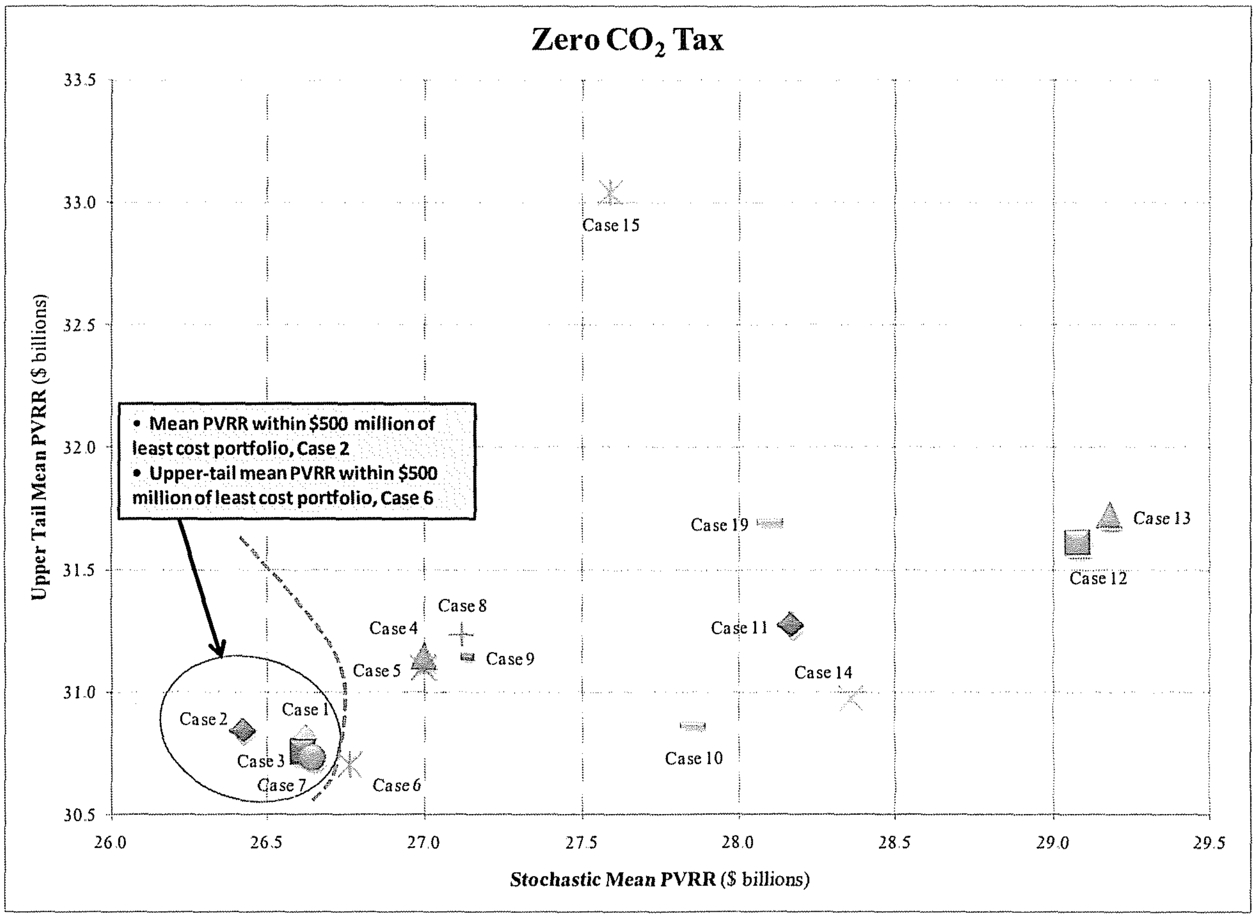
- select the portfolio with the lowest *mean PVRR* as well as portfolios within $500 million of the least-cost portfolio;
- select the portfolio with the lowest *upper-tail PVRR* as well as portfolios within $500 million of the least-cost portfolio, and then;
- select portfolios within both least-cost groups as the top performers for the CO_2 tax scenario.

All portfolios identified as top performers for the four cost comparisons pass the initial screening.

In addition to the three CO_2 tax scenarios, the screening decision rule is applied to the cost averages for the three CO_2 cost scenarios.

The mean and upper-tail portfolio cost comparisons, as well as the top-performing portfolios, are shown graphically with the use of scatter-plot graphs. Figure 7.26 illustrates the application of the decision rule for the zero CO_2 tax scenario results.

Figure 7.26 – Illustrative Stochastic Mean vs. Upper-tail Mean PVRR Scatter-plot



Final Screening

The optimal portfolios for the three CO_2 cost scenarios plus the cost averaging view are evaluated based on the following primary criteria and measures:

- Risk-adjusted PVRR
- Frequency of inclusion in the optimal portfolio group across CO_2 cost scenarios
- 10-year customer rate impact
- Carbon dioxide emissions (generator plus net market transaction contribution)
- Supply reliability – average annual Energy Not Served and upper-tail mean (ENS)

Secondary measures include the following:
- 5th Percentile PVRR
- Production cost standard deviation
- Resource Diversity

The top two portfolios on the basis of the final screen are subjected to a deterministic risk assessment (Phase 6) as the final step before preferred portfolio selection.

Deterministic Risk Assessment

The purpose of Phase 6 is to determine the range of deterministic costs that could result given a fixed set of resources under varying gas/electricity price and CO_2 cost assumptions, the two main sources of portfolio risk. It is used to help validate the selection of the preferred portfolio resulting from the final screening step.

PacifiCorp used the System Optimizer to determine PVRRs for the top-performing portfolios for 10 combinations of CO_2 and natural gas/electricity price scenarios. These price scenario combinations are shown in Table 7.13.

Table 7.13 – Deterministic Risk Assessment Scenarios

CO_2 Tax Level	Base Gas Cost
None	Medium
Medium	Low
High	Low
Low to Very High	Low
Medium	Medium
High	Medium
Low to Very High	Medium
Medium	High
High	High
Low to Very High	High

Resource Acquisition and Regulatory Policy Risk Assessment

Based on phases 5 and 6, a provisional preferred portfolio is selected. For phase 7, the Company looks at fine-tuning the provisional preferred portfolio based on analysis of key resource acquisition and regulatory compliance risks. These risks, and the approach for factoring them into preferred portfolio resource selection, are described below.

Gas Plant Timing

The major resource timing issue for this IRP pertains to a second Utah CCCT targeted for a 2016 acquisition in the Company's 2011 business plan. The IRP portfolios have not been designed to isolate acquisition timing implications for an individual major resource and then determine economic benefits of resource deferral or advancement using stochastic production cost simulation. The purpose of this acquisition risk analysis is to determine if a 2016 in-service date continues to be cost-effective considering stochastic risks, and, adjust if warranted, CCCT timing for the preferred portfolio.

Geothermal Development Risk

As expected, portfolio modeling found geothermal to be cost-effective based on the resource potentials and costs cited in a Black & Veatch/Geothermix report for PacifiCorp (See Chapter 6). In IRP public meetings PacifiCorp cited uncertainty concerning development cost recovery among its state jurisdictions (with the possible exception of Utah) as a significant barrier to exploitation of this resource. The Company addresses geothermal development risk as a non-modeling consideration for selecting preferred portfolio resources.

Regulatory Compliance Risk and Public Policy Goals

The last risk assessment area is uncertainty regarding public policy and specific regulations pertaining to renewable energy acquisition and greenhouse gas reductions. For this final analysis, PacifiCorp determines whether the preliminary preferred portfolio is positioned for addressing regulatory compliance risks and aligns with expected long-term public energy policy goals. To accomplish this, the Company evaluated the renewable energy mix of the core case portfolios that performed the best at minimizing high-cost outcomes (that had the lowest stochastic upper-tail mean PVRR). These portfolios served as benchmarks for developing a single out-year renewable resource schedule that is then integrated into the preliminary preferred portfolio. This renewable resource schedule is also compared with one needed to comply with the Waxman-Markey renewable targets—one of the scenarios investigated as part of the acquisition path analysis described in Chapter 9. This approach aligns with the methodology the Company used to develop a risk reduction cost credit for energy efficiency, described in Chapter 6. The approach also recognizes the importance of strategic positioning in the out-years given the link to transmission planning and the public policy goal of transitioning to a clean energy future.

CHAPTER 8 – MODELING AND PORTFOLIO SELECTION RESULTS

Chapter Highlights

- Portfolios developed based on combinations of natural gas price and CO_2 cost assumptions (core portfolios) exhibited modest resource mix variability in the first 10 years. Every portfolio included a combined-cycle combustion turbine (CCCT) resource in 2014, a second CCCT in either 2015 or 2016, and frequently a third CCCT in 2019.
- Energy efficiency (Class 2 DSM) represents the largest resource added on an average capacity basis across the portfolios through 2030. Cumulative capacity additions ranged from about 2,520 MW to 2,850 MW. The amounts are significantly higher relative to the 2008 IRP and 2008 IRP Update due to larger forecasted potential amounts, updated costs, and a mandated switch to a "Utility Cost" basis for Utah resources.
- Portfolios contained an average of 160 MW of direct load control resources (Class 1 DSM), with the bulk added by 2015.
- Geothermal resources are selected in every portfolio. However, the lack of state legislation and regulatory pre-approval mechanisms for recovery of dry-hole drilling costs prompted PacifiCorp to exclude geothermal resources from the preferred portfolio.
- Wind exhibited the most variability across portfolios, ranging from zero to over 2,700 MW. The preferred portfolio includes 800 MW of wind by 2020 and 2,100 MW by 2029. The wind portfolio selection was impacted by the removal of geothermal resources, recognition of long-term regulatory compliance/incentive uncertainty, long-run public policy goals, and risk mitigation benefits of zero carbon, zero fuel cost renewable resources.
- Distributed generation—specifically, biomass combined heat & power and solar hot water heating—were found to be cost-effective for all portfolios.
- For all the portfolios, front office transactions generally peaked at approximately 1,400 MW in 2013 and dropped to 750 MW each year after 2020.
- PacifiCorp's preferred portfolio consists of the following resources:

	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.

Introduction

This chapter reports modeling and performance evaluation results for the portfolios developed with alternate input assumptions using the System Optimizer model and simulated with the Planning and Risk model. The preferred portfolio is presented along with a discussion of the relative advantages and risks associated with the top-performing portfolios.

Discussion of the portfolio evaluation results falls into the following two main sections.

- Preferred Portfolio Selection – This section covers: (1) development of the core case portfolios, (2) stochastic production cost modeling results for these portfolios, (3) portfolio screening results (initial and final screens), (4) evaluation of the top-performing portfolios, including the deterministic risk assessment, and (5) preferred portfolio selection.

- Portfolio Sensitivity Analysis – This section covers development and analysis of sensitivity portfolios relative to a base portfolio, as well as the coal plant utilization study and Energy Not Served price sensitivity study.

Preferred Portfolio Selection

Core Case Portfolio Development Results

Table 8.1 shows the cumulative capacity additions by resource type for each of the core cases for years 2011-2030. Megawatt amounts for front office transactions and growth resources represent annual averages: 20 years for FOT, and 10 years for growth resources. (The detailed portfolio resource tables are included in Appendix A, along with PVRR results.)

Resource Selection
Resource selection patterns across portfolios include the following:

<u>Gas Resources</u>

- Every portfolio has a CCCT (North Utah, wet-cooled 2x1 F class) selected in 2014. Also noteworthy is that under the low economic growth scenario, a CCCT was selected for 2014.
- A second CCCT is selected predominately for 2015, although a number of portfolios include a CCCT in 2016 or 2018. The timing is on the "knife edge", and is driven primarily by natural gas prices. All the high gas price cases have the CCCT added in 2016 or 2018. Under the low economic growth scenario (Case 25), the second CCCT was deferred to 2018.
- A third CCCT is generally selected in 2019 (H class, located in Utah) under low and medium natural gas price scenarios. Under high gas price cases, the model replaces the third CCCT with west-side geothermal and additional DSM resources in both the east and west.

Table 8.1 – Total Portfolio Cumulative Capacity Additions by Case and Resource Type, 2011 – 2030

20-year resource totals (MW capacity)

Case	Core 1	Core 2	Core 3	Core 4	Core 5	Core 6	Core 7	Core 8	Core 9	Core 9a	Core 10	Core 11	Core 12	Core 13	Core 14	Core 15	Core 16	Core 17	Core 18	Core 19	Avg	Min	Max
CO_2 cost	None	None	Medium	High	Low to very high	Low to very high	Medium	High	Low to very high	Low to very high	Low to very high	Medium	High	Low to very high	Low to very high	Medium	Medium	Medium	Medium	Business Plan (BP)			
Natural gas cost	Medium	Medium	Low	Low	Low	Low	Medium	Medium	Medium	Medium	Medium	High	High	High	High	Low	Medium	High	Medium	BP			
Transmission scenario [1]	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3			
Resource																							
East																							
Coal																							
Coal Plant Turbine Upgrades	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
CCS																							
CCS Hunter - Unit 3 (Replaces Original Unit)	0	0	0	280	280	280	0	280	280	280	280	0	280	280	280	280	280	280	280	0	196	0	280
CHP																							
CHP - Biomass	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	10	20	10	20
CHP - Reciprocating Engine	4	6	5	2	5	2	2	2	2	3	2	3	2	3	5	6	2	2	2	0	3	0	6
DSM, Class 1	95	102	97	102	97	96	100	99	99	92	99	102	99	102	101	97	92	99	86	102	98	86	102
DSM, Class 2	1,300	1,361	1,384	1,441	1,431	1,402	1,380	1,457	1,461	1,460	1,451	1,553	1,527	1,562	1,599	1,404	1,446	1,568	1,463	1,532	1,459	1,300	1,599
Gas																							
CCCT F 2x1	1,222	1,222	1,222	1,222	1,819	1,819	1,222	1,222	1,819	1,819	1,819	1,222	1,222	1,222	625	1,222	1,222	1,222	1,222	1,819	1,371	625	1,819
CCCT H	475	475	475	1,425	2,375	2,375	475	475	1,425	1,425	950	0	0	0	475	1,425	1,900	0	2,375	0	926	0	2,375
SCCT Aero Utah	0	0	0	0	0	0	0	0	0	0	118	0	0	0	118	0	0	0	0	0	12	0	118
Geothermal																							
Geothermal, Blundell 3	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Geothermal, Greenfield	35	0	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	0	32	0	35
Nuclear																							
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	1,600	1,600	0	0	1,600	0	0	240	0	1,600
Solar																							
Micro Solar - Water Heater	28	24	37	39	36	26	29	34	37	23	26	37	42	45	45	37	34	45	34	0	33	0	45
Wind																							
Wind, Wyoming NE, 35% Capacity Factor	0	0	0	0	0	160	160	0	0	0	160	0	160	0	160	0	0	160	0	160	56	0	160
Wind, WY 35% CF	143	0	139	136	227	145	55	50	500	418	600	0	1,800	1,600	2,000	139	50	2,240	308	1,100	583	0	2,240
FOT (20yr Average)																							
FOT Mead 3rd Qtr HLH	40	37	36	36	36	40	36	36	36	40	37	40	40	40	45	38	38	40	36	40	38	36	45
FOT Mona-3 3rd Qtr HLH	255	255	255	255	210	210	255	255	240	240	240	255	255	255	255	255	246	255	195	255	245	195	255
FOT Utah 3rd Qtr HLH	57	54	54	52	54	60	44	52	53	56	51	50	50	50	71	53	53	50	52	60	54	44	71
FOT Mona-4 3rd Qtr HLH	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Growth Resource (10yr Average)																							
Growth Resource Goshen	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Growth Resource Utah North	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	46	10	100	0	100	88	0	100
Growth Resource Wyoming	100	100	100	100	100	100	100	100	100	100	100	100	100	100	80	100	97	100	21	100	95	21	100
West																							
Coal																							
Coal Plant Turbine Upgrades	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
CCS																							
CCS Bridger - Unit 1 (Replaces Original Unit)	0	0	0	227	227	227	0	227	227	227	227	0	227	227	227	227	227	227	227	0	159	0	227
CCS Bridger - Unit 2 (Replaces Original Unit)	0	0	0	216	216	216	0	216	216	216	216	0	216	216	216	216	216	216	216	0	151	0	216
CHP																							
CHP - Biomass	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	42	82	42	84
CHP - Reciprocating Engine	2	3	1	1	1	1	1	1	1	1	1	1	1	1	2	2	1	0	1	0	1	0	3
DSM, Class 1	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	56	60	56	60	59	56	60
DSM, Class 2	1,226	1,239	1,239	1,257	1,253	1,247	1,243	1,260	1,260	1,260	1,258	1,266	1,269	1,270	1,269	1,251	1,259	1,274	1,261	1,272	1,257	1,226	1,274
Geothermal																							
Geothermal, Greenfield	70	0	105	105	70	105	70	140	245	280	490	420	420	420	408	105	140	420	105	0	206	0	490
Other																							
Utility Biomass	50	50	0	0	0	0	0	0	0	50	50	50	50	50	50	0	0	50	0	0	23	0	50
Solar																							
Oregon Solar Cap Standard	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Oregon Solar Pilot	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Micro Solar - Water Heater	15	16	18	21	20	15	19	20	21	12	18	24	29	30	29	16	19	31	20	0	20	0	31
Wind																							
Wind, Yakima, 29% CF	0	0	0	0	0	0	0	0	0	0	0	100	100	100	200	0	0	100	100	0	35	0	200
Wind, Walla Walla, 29% CF	0	0	0	0	0	0	0	0	0	0	0	0	100	0	0	0	0	100	0	0	10	0	100
FOT (20yr Average)																							
FOT COB 3rd Qtr HLH	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
FOT MidColumbia 3rd Qtr HLH	372	370	337	231	243	248	354	279	275	270	275	355	333	315	313	315	280	332	197	368	303	197	372
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	22	22	23	23	23	23	24	23	23	22	23	22	22	22	22	23	23	22	22	22	23	22	24
FOT South Central Oregon/Northern California 3rd Qtr HLH	39	40	18	18	18	18	18	18	18	18	20	17	13	16	18	33	37	35	30	20	23	13	40
Growth Resource (10yr Average)																							
Growth Resource Walla Walla	100	78	100	100	0	0	48	100	23	23	47	20	73	18	38	0	0	0	0	7	39	0	100
Growth Resource Oregon / California	4	68	100	100	50	38	41	100	45	14	76	29	56	0	0	0	0	20	0	0	37	0	100
Growth Resource Yakima	119	100	100	200	120	129	200	200	200	200	200	200	200	200	200	100	100	100	100	166	157	100	200

1. Transmission Scenario is referencing the scenario as described in the Portfolio Case Development paper.

Demand-side Management

- Energy efficiency (Class 2 DSM) represents the largest resource through 2030 on an average capacity basis across the portfolios, followed by CCCTs.
- Energy efficiency additions occur steadily throughout the simulation period; variability across portfolios is not large, and is within a range of about 330 MW.
- Greater reliance on energy efficiency relative to the 2008 IRP is due to larger forecasted potential amounts and the application of new or updated cost credits, along with a switch to a "Utility Cost" basis for Utah resources (See Chapter 6).
- The model selected an average of 160 MW of dispatchable load control (Class 1 DSM) across the core case portfolios through 2030, with the bulk added in 2012 in the east and 2013 in the west.

Geothermal

- Geothermal is heavily exploited, particularly in the near term, due to favorable baseload economics, availability of the federal production tax credit which is assumed to end by 2015, state renewable energy targets, and lack of competition from Wyoming wind until 2018 when Gateway West is assumed to be in service.
- The Utah Blundell geothermal resource—proposed unit 3 and additional expansion at Roosevelt Hot Springs for a total of 80 MW—is selected in every portfolio; unit 3 is selected in the earliest year available, 2015, while the remaining resource is acquired by 2020.
- Geothermal resources at new sites in the east (greenfield development) totaling 35 MW, and west-side greenfield geothermal (ranging from 70 to 560 MW), are selected in all but two portfolios. Either CO_2 costs or state RPS requirements are needed to prompt selection of west-side geothermal selection in 2015.
- Higher CO_2 cost scenarios—"High" and "Low to Very High"—drives the model to rely on west-side geothermal by 2020.

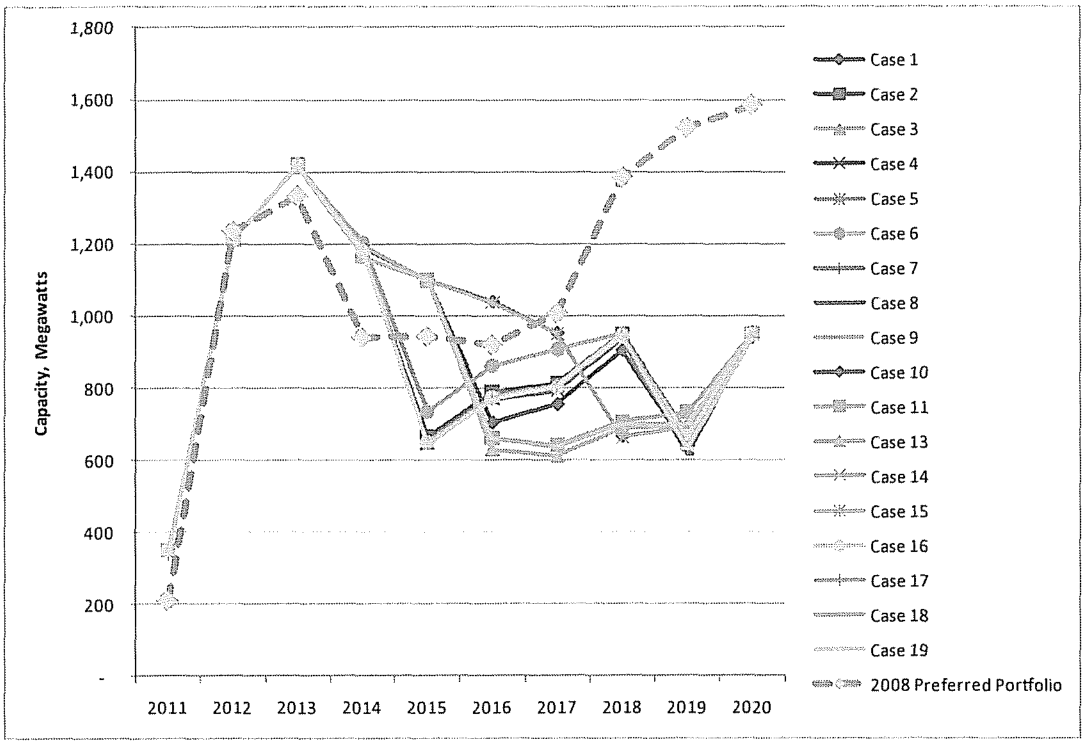
Wind

- Consistent with wind selection patterns for the 2008 IRP portfolios, this resource exhibited the most variability, ranging from none selected in Case 2 (no RPS requirement) to 2,730 MW in Case 17 (CO_2 emission hard cap with high gas prices).
- Reliance on wind is diminished overall across the portfolios relative to the 2008 IRP core case portfolios due to changes in the assumed duration of federal renewable PTC (extension to 2015 or 2020 for the 2011 IRP, versus extension to the end of the 20-year simulation period for the 2008 IRP), as well as lower starting points for CO_2 tax values.

Front Office Transactions

- All the portfolios exhibit the same annual acquisition pattern for front office transactions through 2014, increasing to a peak of about 1,420 MW in 2013, and then decreasing to a low of about 750 MW post-2020. Variability between 2015 and 2020 averages about 330 MW across the portfolios. Figure 8.1 shows annual 10-year trends for FOT by portfolio. The 10-year trend for the 2008 IRP preferred portfolio is shown with the red dashed line, indicating that reliance on FOT is significantly reduced beyond 2017 for the 2011 IRP core portfolios.

Figure 8.1 – Front Office Transaction Addition Trends by Portfolio, 2011-2020



<u>Distributed Generation</u>

- The model selected solar hot water heating resources in all portfolios, with additions of about 4.5 MW per year through the mid-2020s. For the east-side and west-side, the model was allowed to select up to 3.1 MW and 1.8 MW per year, respectively. The typical annual values selected were 2.6 MW for the east-side and the full 1.8 MW amount for the west-side.
- The model consistently added 104 MW of biomass-based combined heat & power (CHP) for the portfolios by 2030; a small amount of reciprocating engine-based CHP was also added, averaging a cumulative 4 MW by 2030 across the portfolios.

<u>Nuclear, Coal Plant Carbon Capture & Sequestration, and Energy Storage</u>

- Nuclear and coal plant carbon capture & sequestration (CCS) resources were allowed to be selected only in 2030. Nuclear was selected in three portfolios, requiring high gas cost assumptions and aggressive carbon regulation in the form of the "Low to Very High" CO_2 tax levels or a CO_2 emission hard cap.
- The model selected no energy storage resources in any of the portfolios.

Carbon Dioxide Emissions

Figures 8.2 through 8.6 show annual portfolio emission reductions by CO_2 tax and policy type. Figure 8.2, which shows the medium CO_2 tax portfolios, also includes the 2011 IRP preferred portfolio described later in this chapter. The 2005 system emission baseline amount of 61 million short tons is also shown for reference purposes. The System Optimizer emission quantities account for generation as well as market purchases (front office transactions, spot market transactions for system energy balancing, and growth resources). Note that the significant drop in emissions in

2015 is due to the start of the assumed CO_2 tax. Large emission reductions in 2030 are due to the addition of clean baseload resources (nuclear and coal plant CCS retrofits), which are only available in that year. While this represents an optimization end effects issue, is does highlight the impact of such resources on the CO_2 emissions footprint.

Figure 8.2 – Annual CO_2 Emissions: Medium CO_2 Tax Scenario

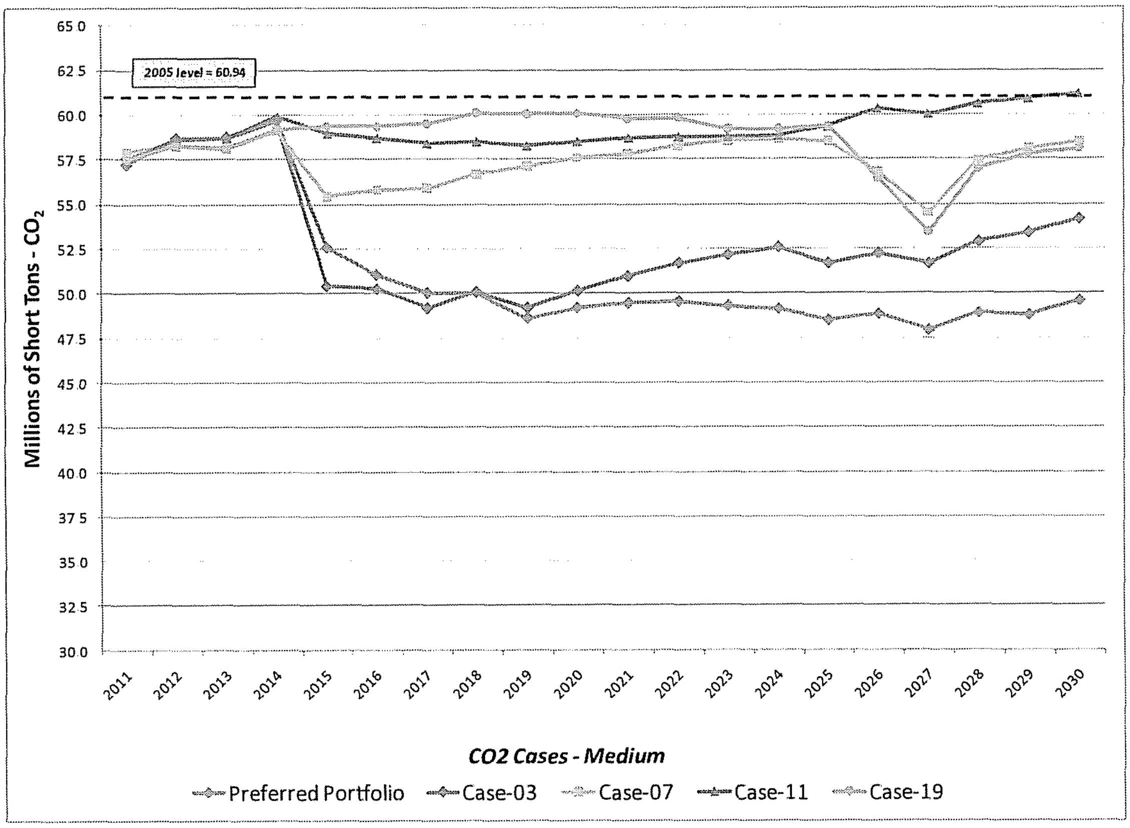


Figure 8.3 – Annual CO_2 Emissions: High CO_2 Tax Scenario

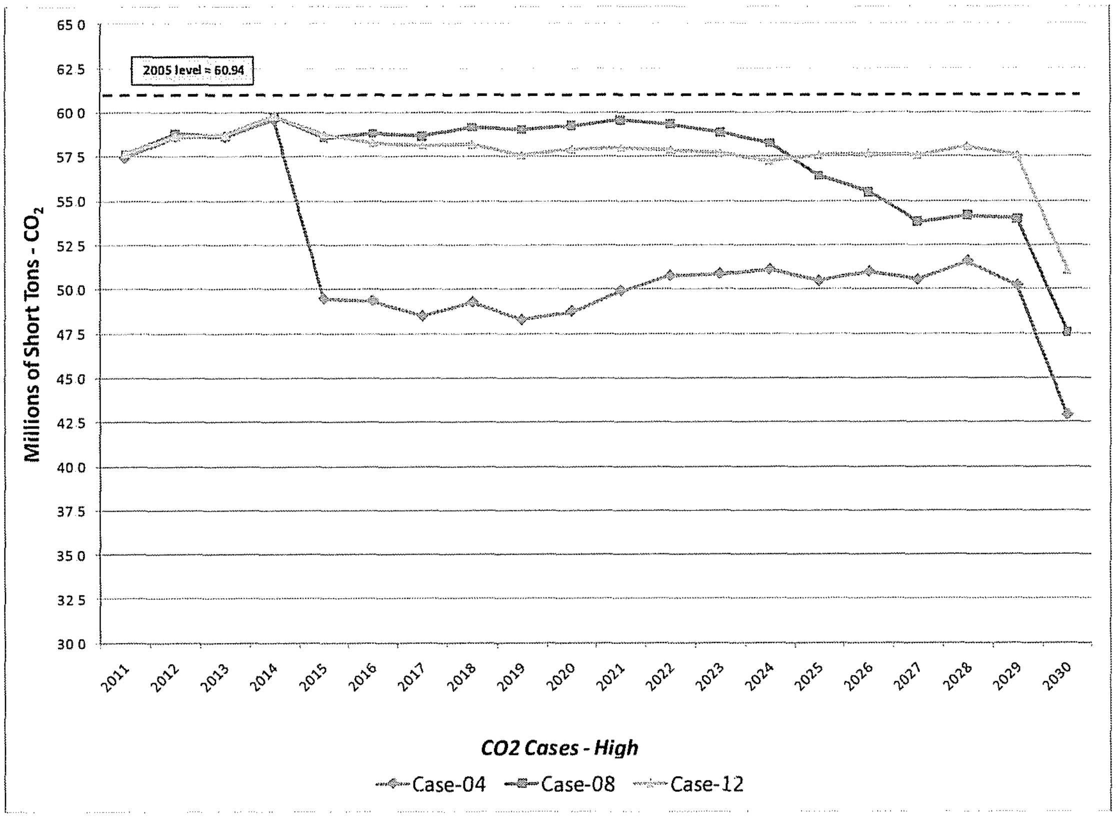


Figure 8.4 – Annual CO_2 Emissions: Low to Very High CO_2 Tax Scenario

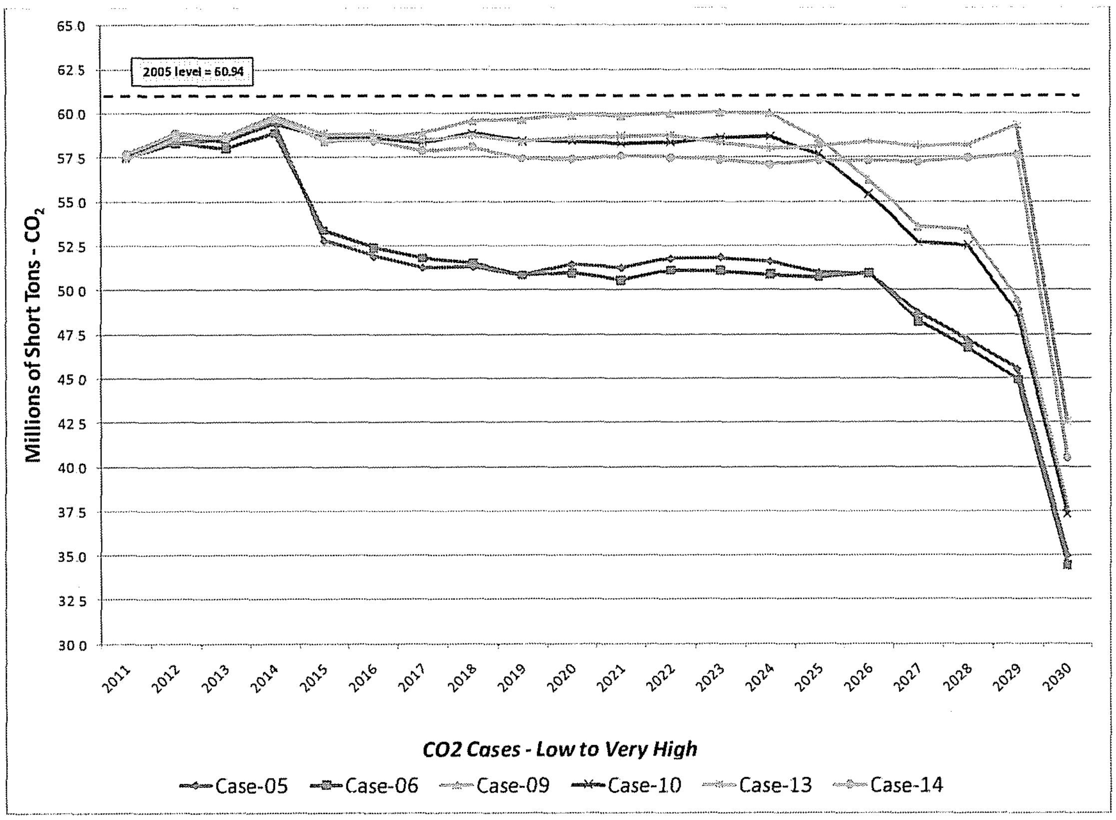


Figure 8.5 – Annual CO_2 Emissions: Hard Cap Scenarios

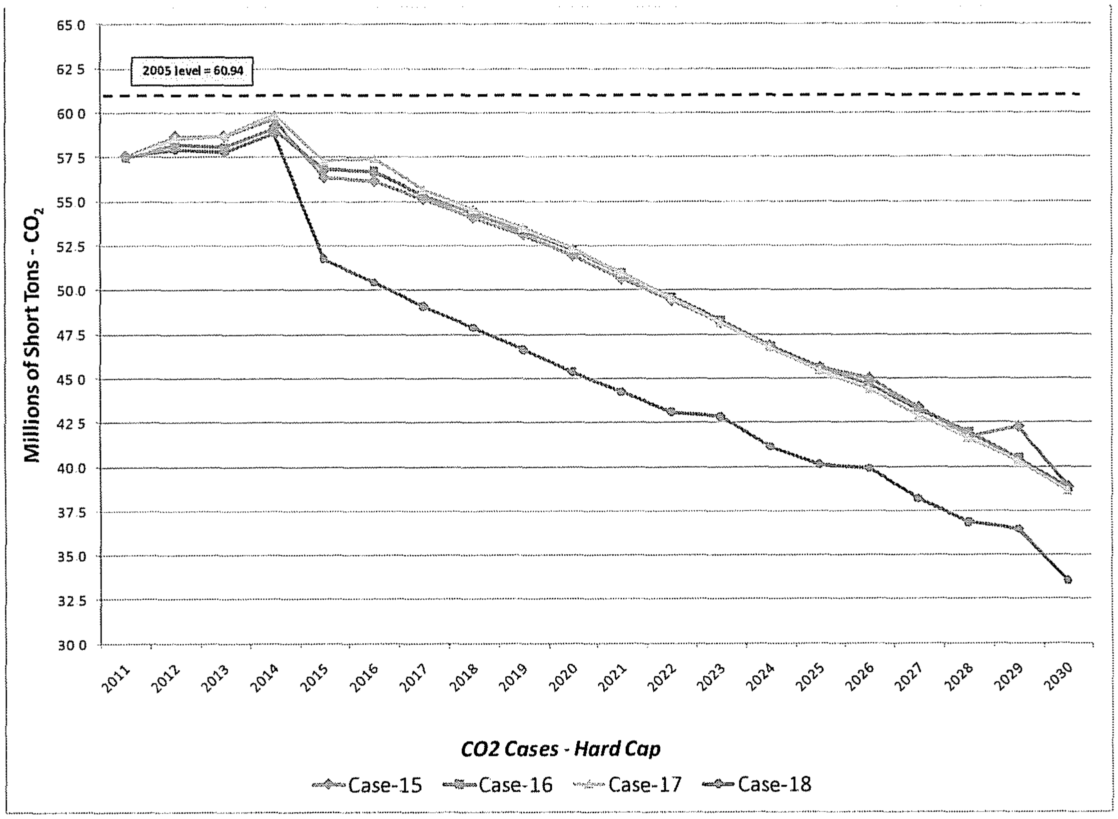
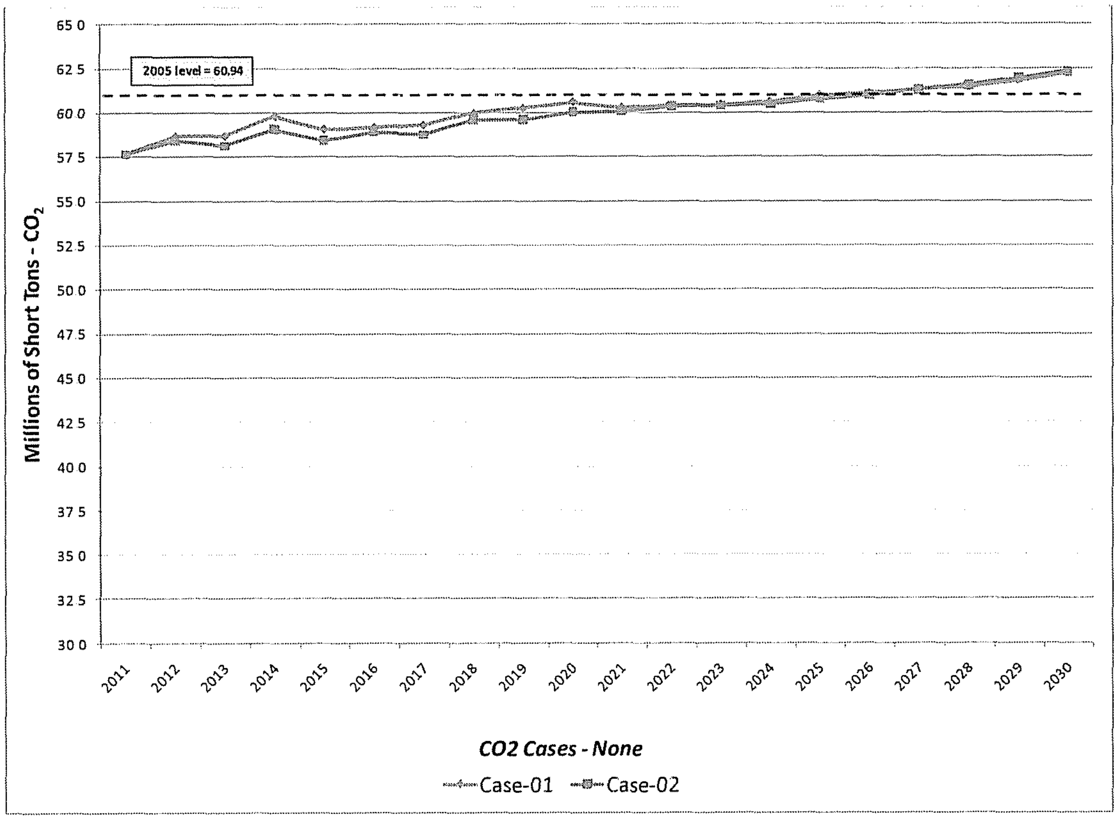


Figure 8.6 – Annual CO_2 Emissions: No CO_2 Tax

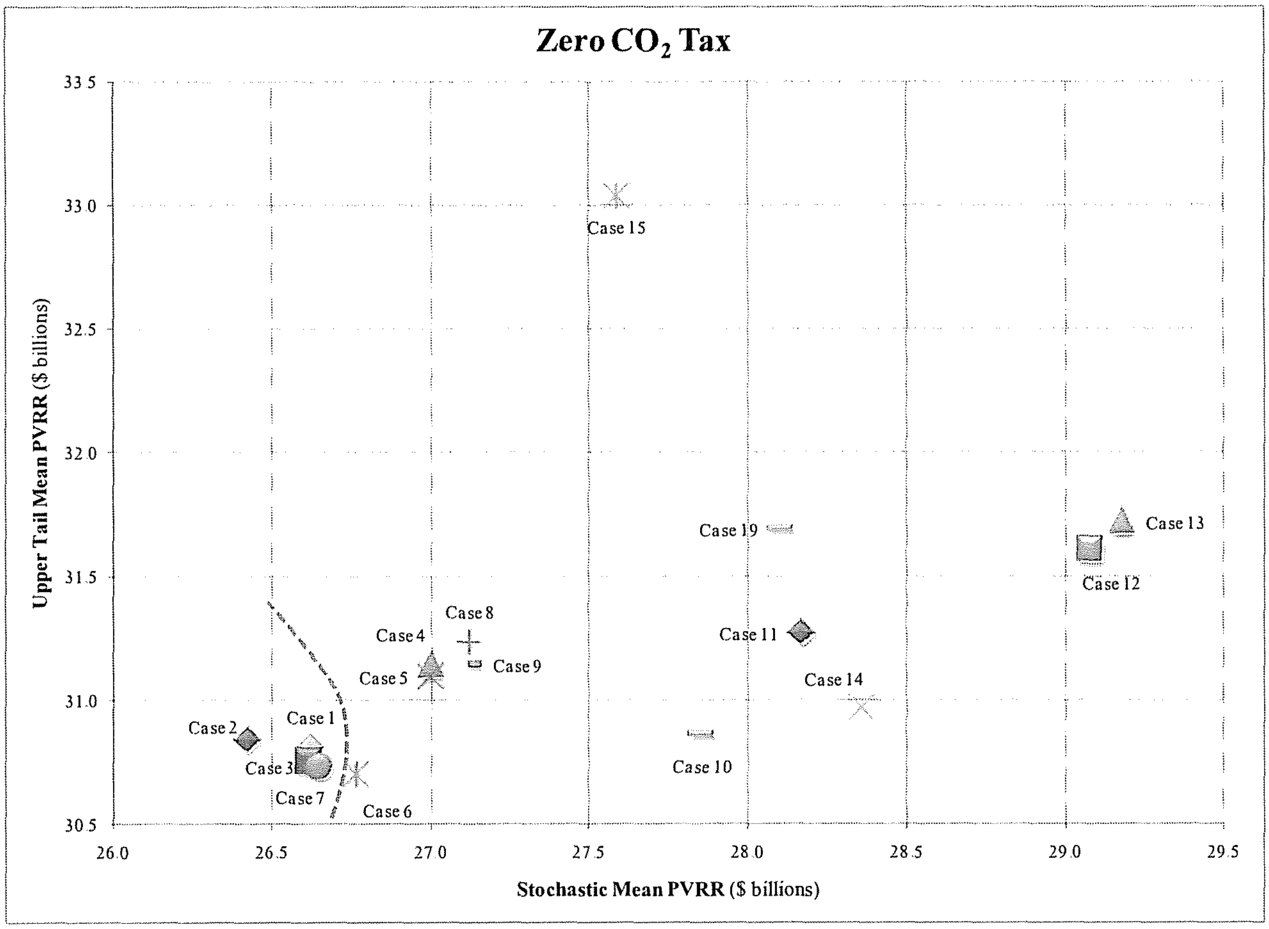


Initial Screening Results

Figure 8.7 shows the upper-tail cost versus mean cost scatter-plot chart for the zero CO_2 tax scenario.[67] The red line demarcates the group of four portfolios—cases 1, 2, 3, and 7—designated as superior with respect to the combination of upper-tail and mean cost using the $500 million threshold for both mean PVRR and upper-tail mean PVRR. For example, case 6 was excluded because its mean PVRR difference relative to the top-performing portfolio (case 2) was $584 million, exceeding the $500 million threshold. (As a reminder, all stochastic production cost runs are based on the medium natural gas price forecast.) Note that PacifiCorp excluded some of the hard cap portfolios from the charts—for example, Cases 17 and 18—due to outlying PVRRs that impacted legibility. Appendix E includes scatter-plot graphs showing all core case portfolios.

Portfolios in the top-performing group were more reliant on gas, distributed generation, and front office transactions (in the out-years) relative to the others, and less reliant on energy efficiency, wind, and geothermal resources.

Figure 8.7 – Stochastic Cost versus Upper-tail Risk, $0 CO_2 Tax Scenario



[67] PacifiCorp recently updated the Case 13 and 14 portfolios to correct for a natural gas price input error. The stochastic results have not been updated, but the PVRR for Case 14 would be expected to increase due to the revised resource mix.

Outlier portfolios, Cases 12 and 13, include large quantities of clean generating capacity; almost 2,600 MW of wind in the Case 12 portfolio, and 3,200 MW of nuclear capacity and 1,700 MW of wind in Case 13.

Figure 8.8 shows the mean cost versus upper-tail cost scatter-plot chart for the medium ($19/ton) CO_2 tax scenario. Two of the CO_2 hard cap portfolios (Cases 17 and 18) were excluded from the chart because they resulted in extreme outlying PVRRs. The red line demarcates the nine portfolios—1, 2, 3, 4, 5, 6, 7, 9, and 15—designated as superior with respect to the combination of upper-tail and mean cost.

Portfolios in the top-performing group were more reliant on gas and front office transactions, and less reliant on wind and geothermal resources.

Figure 8.8 – Stochastic Cost versus Upper-tail Risk, Medium CO_2 Tax Scenario

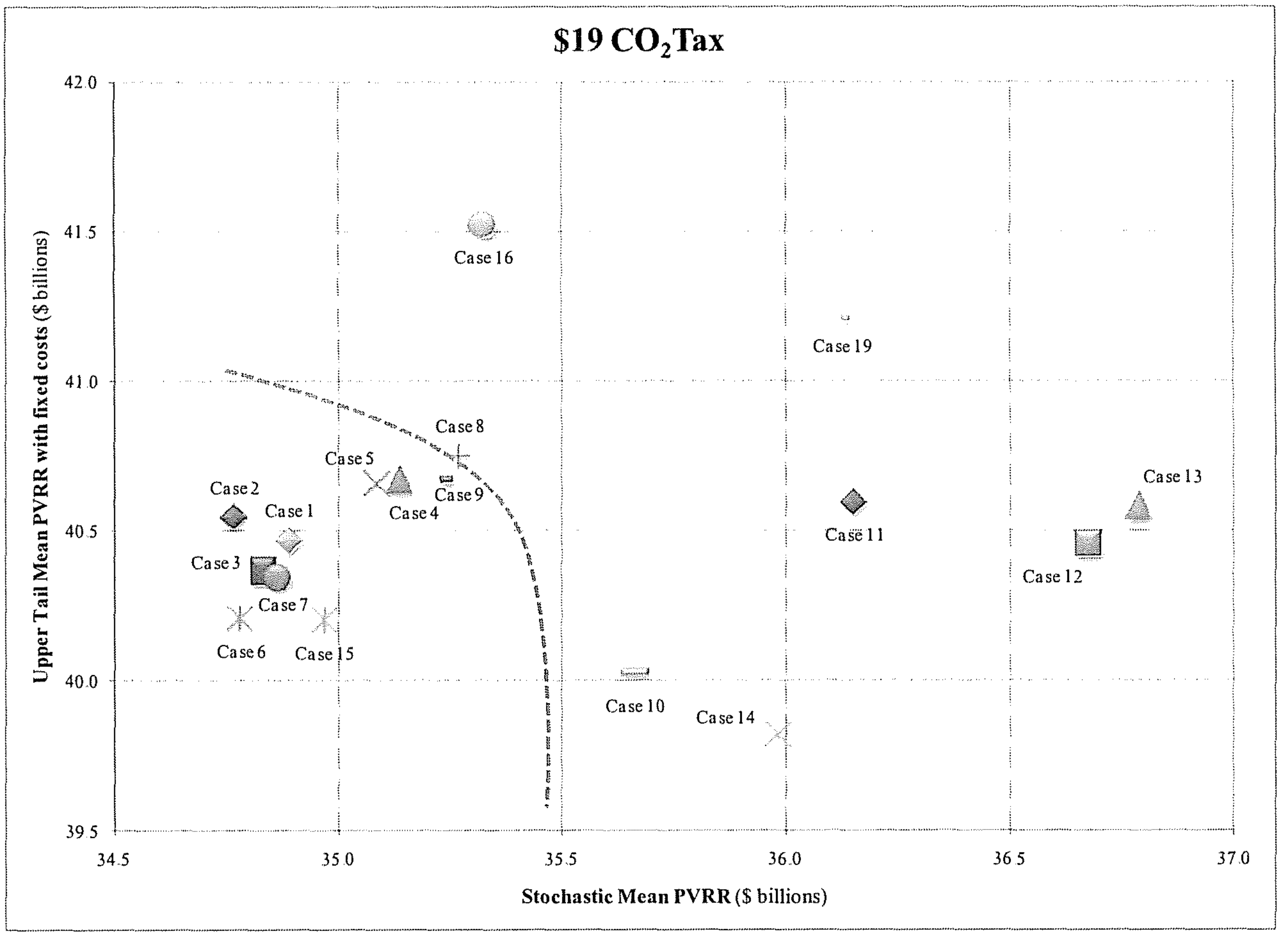


Figure 8.9 shows the mean cost versus upper-tail cost scatter-plot chart for the Low to Very High CO_2 tax scenario ($12/ton escalating to $93/ton by 2030). Two of the CO_2 hard cap portfolios were again excluded from the chart because they resulted in extreme outlying PVRR results. Cases 1, 3, 5, 6, 7, 9, and 15 have the lowest combination of upper-tail and mean cost.

Portfolios in the top-performing group were more reliant on gas, but less reliant on wind, geothermal, and energy efficiency than the others.

Figure 8.9 – Stochastic Cost versus Upper-tail Risk, Low to Very High CO_2 Tax Scenario

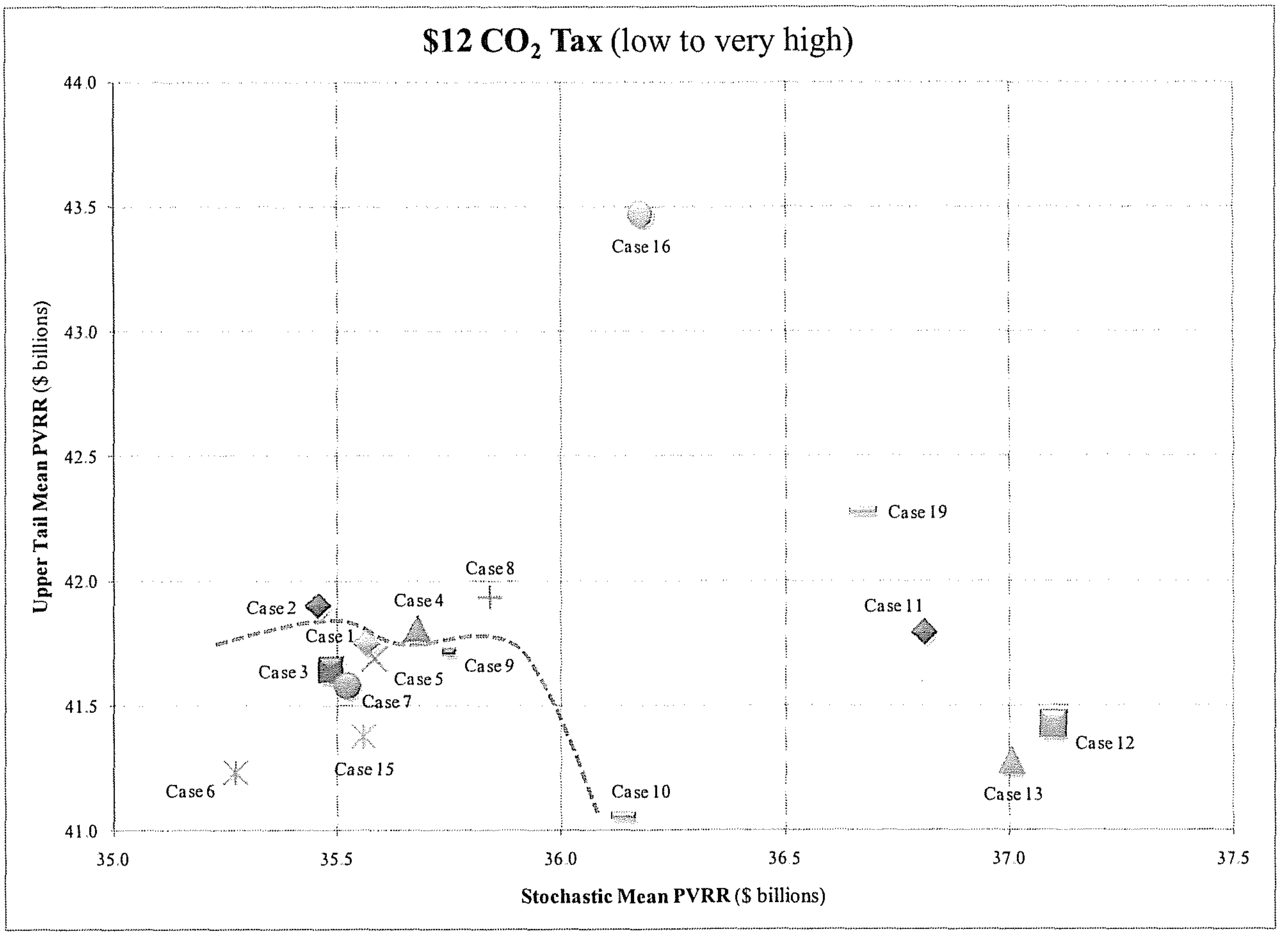
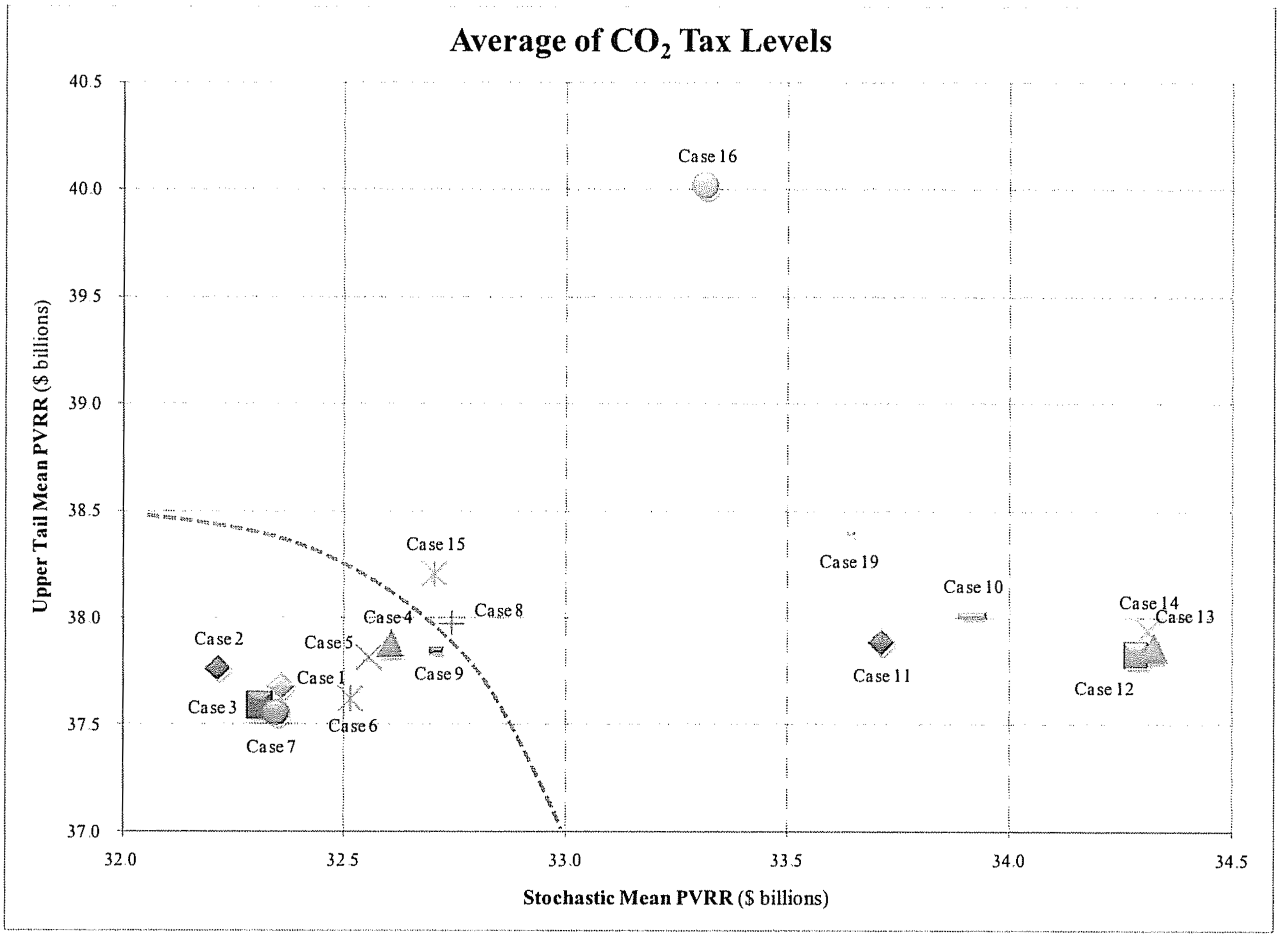


Figure 8.10 shows the mean cost versus upper-tail cost scatter-plot chart for the averaged PVRR results across the CO_2 tax scenarios. Averaging cost results for the three CO_2 cost scenarios yields a tighter clustering of portfolios. Cases selected as the top-performers include 1, 2, 3, 4, 5, 6, 7, and 9.

Figure 8.10 – Stochastic Cost versus Upper-tail Risk, Average of CO_2 Tax Scenarios



Based on the mean versus upper-tail cost comparisons, PacifiCorp selected eight of the 19 core case portfolios for the final screening—1, 3, 4, 5, 6, 7, 9, and 15. The Case 2 portfolio does not comply with state renewable portfolio standards, and was therefore rejected as a preferred portfolio contender. (Note that stochastic cost and risk measures are reported for this portfolio in Appendix E.) Table 8.2 summarizes the selection results for each of the CO_2 tax scenarios and the averaged results across CO_2 tax scenarios.

Table 8.2 – Initial Screening Results, Stochastic Cost versus Upper-tail Risk

CO_2 Tax Scenario (Price Range, 2015-2030)	None ($0)	Medium ($1 - $39)	Low to Very High ($12 - $93)	Average (None, Medium, Low to Very High)	Final Screening Selections
Cases Selected	1	1	1	1	1
	3	3	3	3	3
	7	4	5	4	4
		5	6	5	5
		6	7	6	6
		7	9	7	7
		9	15	9	9
		15			15

Final Screening Results

Risk-adjusted PVRR

Table 8.3 reports the risk-adjusted PVRR results for the eight case portfolios by CO_2 tax scenario selected for final screening. In addition to rankings, the table shows the cost spread between a case portfolio and the lowest-cost case portfolio for each CO_2 tax scenario group. Cases 1 and 3 have the lowest risk-adjusted PVRR under the $0 and Medium CO_2 tax scenarios, whereas Cases 3 and 6 have the lowest values under the Low to Very High scenario. On an average cost basis (two columns far right), Cases 3 and 7 perform the best.

Table 8.3 – Portfolio Comparison, Risk-adjusted PVRR

	Risk-adjusted PVRR (Million $)											
	CO_2 Tax Scenario, $/ton											
Case	None ($0)	Cost Spread Relative to Lowest Cost Case	Rank	Medium ($19 -$39)	Cost Spread Relative to Lowest Cost Case	Rank	Low to Very High ($12 - $93)	Cost Spread Relative to Lowest Cost Case	Rank	CO_2 Scenario Average	Cost Spread Relative to Lowest Cost Case	Rank
1	27,819	11	2	36,561	62	3	37,311	94	5	33,897	54	3
3	27,808	0	1	36,499	0	1	37,223	6	2	33,843	0	1
4	28,207	399	6	36,811	311	7	37,419	203	7	34,146	302	6
5	28,194	386	5	36,747	248	6	37,313	96	6	34,085	241	5
6	28,182	374	4	36,661	162	5	37,216	0	1	34,020	176	4
7	27,842	34	3	36,530	31	2	37,261	45	3	33,878	34	2
9	28,323	515	7	36,896	397	8	37,470	253	8	34,230	386	7
15	28,882	1,074	8	36,614	114	4	37,275	59	4	34,257	414	8

10-year Customer Rate Impact

Table 8.4 reports the 10-year customer rate impacts for the eight case portfolios by CO_2 tax scenario. Rate impacts are expressed as the 10-year cumulative percentage increase relative to the 2010 forecasted system full revenue requirements.

Table 8.4 – Portfolio Comparison, 10-year Customer Rate Impact

	10-year Customer Rate Impact (Cumulative Percentage Rate Increase, 2011 - 2020)											
	CO_2 Tax Scenario, $/ton											
Case	None ($0)	Percent Spread Relative to Lowest Case	Rank	Medium ($19 -$39)	Percent Spread Relative to Lowest Case	Rank	Low to Very High ($12 - $93)	Percent Spread Relative to Lowest Case	Rank	CO_2 Scenario Average	Percent Spread Relative to Lowest Case	Rank
1	22.62%	0.05%	2	39.64%	0.09%	4	33.56%	0.08%	2	31.94%	0.07%	2
3	22.57%	0.00%	1	39.55%	0.00%	1	33.48%	0.00%	1	31.87%	0.00%	1
4	22.88%	0.30%	5	39.84%	0.30%	6	33.78%	0.30%	6	32.17%	0.30%	5
5	22.68%	0.10%	4	39.65%	0.10%	5	33.59%	0.10%	4	31.97%	0.10%	4
6	23.26%	0.69%	7	39.92%	0.37%	8	34.01%	0.53%	8	32.40%	0.53%	7
7	22.66%	0.08%	3	39.62%	0.08%	2	33.56%	0.08%	3	31.95%	0.08%	3
9	22.89%	0.31%	6	39.85%	0.31%	7	33.79%	0.31%	7	32.18%	0.31%	6
15	24.06%	1.49%	8	39.63%	0.09%	3	33.75%	0.27%	5	32.48%	0.61%	8

The Case 3 portfolio performs the best across all CO_2 tax scenarios, followed by the Case 1 and Case 7 portfolios.

Cumulative Carbon Dioxide Emissions

Table 8.5 reports the PaR model's cumulative 20-year generator CO_2 emissions (average of the 100 Monte Carlo iterations) for each of the eight portfolios. The Case 5 and 6 portfolios have the lowest emissions among the non-hard cap portfolios. As discussed above, the hard cap cases are modeled with shadow emission prices from System Optimizer rather than the CO_2 tax values used for the other cases (See Table 7.4). While the Company adjusted portfolio costs for the hard cap cases to reflect the CO_2 tax scenario values, the emissions are driven by the shadow costs.

Table 8.5 –Portfolio Comparison, Cumulative Generator CO_2 Emissions for 2011-2030

	Cumulative Carbon Dioxide Emissions for 2011 - 2030 (Short Tons)											
	CO_2 Tax Scenario, $/ton											
Case	None ($0)	Spread Relative to Lowest Case	Rank	Medium ($19 -$39)	Spread Relative to Lowest Case	Rank	Low to Very High ($12 - $93)	Spread Relative to Lowest Case	Rank	CO_2 Scenario Average	Spread Relative to Lowest Case	Rank
1	941,203	126,522	8	842,439	21,733	7	801,497	23,897	8	861,713	36,676	8
3	937,901	123,220	6	837,918	17,211	5	796,784	19,184	5	857,534	32,498	6
4	930,958	116,277	5	829,216	8,510	4	787,440	9,839	4	849,205	24,168	5
5	929,942	115,261	3	826,233	5,527	2	782,864	5,263	2	846,346	21,310	3
6	924,985	110,303	2	820,706	-	1	777,600	-	1	841,097	16,060	2
7	938,503	123,821	7	838,639	17,933	6	797,611	20,011	6	858,251	33,214	7
9	930,726	116,045	4	828,225	7,518	3	785,834	8,233	3	848,262	23,225	4
15	814,681	-	1	859,920	39,213	8	800,509	22,909	7	825,037	-	1

Supply Reliability

Table 8.6 reports two measures of stochastic supply reliability: average annual Energy Not Served (ENS) and upper-tail mean Energy Not Served. The portfolios for Case 5 and 6 perform the best on these two measures. These results are for the $19/ton CO_2 tax scenario. Differences are not material between CO_2 tax scenarios.

Table 8.6 – Portfolio Comparison, Energy Not Served

Case	Average Annual Energy Not Served, 2011-2030 (GWh)	ENS Spread Relative to Lowest Case	Rank	Upper-tail Mean Energy Not Served Cumulative Total, 2011-2030 (GWh)	ENS Spread Relative to Lowest Case	Rank
1	46.9	7.9	8	48.8	9.1	8
3	44.3	5.2	6	45.7	6.0	6
4	41.1	2.1	4	42.0	2.3	4
5	39.0	0.0	1	39.7	0.0	1
6	39.2	0.1	2	39.7	0.0	2
7	45.5	6.5	7	47.0	7.3	7
9	39.7	0.7	3	40.1	0.4	3
15	41.6	2.6	5	42.7	3.1	5

Resource Diversity

Table 8.7 reports the generation shares for each portfolio by resource category for 2020. The resource categories include thermal, renewable, and DSM. The Case 6 portfolio has the highest renewable generation share due to more wind resources, but has the lowest share of DSM. Portfolios for Case 1 and 9 have high renewable shares reflecting the addition of a 50 MW utility-scale biomass resource. The Case 1 and 7 portfolios have the highest shares of renewables and DSM combined, at a respective 40.4 percent and 40.2 percent.

Table 8.7 – Generation Shares by Resource Type, 2020

Case	Thermal	Renewable	DSM	Combined Renewables/DSM
1	51.8%	10.9%	29.5%	40.4%
3	61.1%	8.6%	24.2%	32.8%
4	61.1%	8.5%	24.3%	32.8%
5	60.7%	8.7%	24.5%	33.1%
6	58.3%	12.8%	22.9%	35.7%
7	52.3%	10.4%	29.7%	40.2%
9	52.9%	10.3%	29.4%	39.7%
15	61.1%	8.6%	24.2%	32.8%

Final Screening and Preliminary Preferred Portfolio Selection

Selection of the Top Three Portfolios

PacifiCorp narrowed down the eight portfolios to three top candidates for preliminary preferred portfolio selection. Table 8.8 summarizes the performance of the three portfolios selected—Cases 1, 3, and 7—based on the various primary and secondary portfolio performance measures described in Chapter 7:

Table 8.8 – Top-three Portfolio Comparison, Final Screening Performance Measures

Performance Characteristic	Case 1	Case 3	Case 7
Primary Measures			
Least-cost/least-risk group (initial screening)	One of only three portfolios selected in all four least-cost/least risk groups (See Table 8.2)	One of only three portfolios selected in all four least-cost/least risk groups (See Table 8.2)	One of only three portfolios selected in all four least-cost/least risk groups (See Table 8.2)
Risk-adjusted cost	Ranked second under the \$0 CO_2 tax scenario; ranked third under the Medium CO_2 tax scenario	Ranked first under the \$0, Medium, and averaged CO_2 tax scenarios; ranked second under the Low to Very High CO_2 tax scenario	Ranked second under the Medium and averaged CO_2 tax scenarios; ranked third under the Low to Very High CO_2 tax scenario

Performance Characteristic	Case 1	Case 3	Case 7
10-year customer rate impact	Ranked second under the $0 and averaged CO_2 tax scenarios; ranked third under Low to Very High CO_2 tax scenario	Ranked first under all CO_2 tax scenarios	Ranked second under the Medium and Low to Very High CO_2 tax scenarios; ranked third under the $0 and averaged CO_2 tax scenarios
CO_2 Emissions	Not among the top three portfolios; highest emissions among Case 1, 3, and 7 portfolios	Not among the top three portfolios; lowest emissions among Case 1, 3, and 7 portfolios	Not among the top three portfolios; second after Case 3 on emissions
Supply Reliability (Energy Not Served)	Not among the top three portfolios; highest mean and upper-tail mean ENS among Case 1, 3, and 7 portfolios	Not among the top three portfolios; lowest mean and upper-tail mean ENS among Case 1, 3, and 7 portfolios	Not among the top three portfolios; second after Case 3 on mean and upper-tail mean ENS
Resource Diversity	Highest combined renewable/DSM generation share for 2020	Not among the top three portfolios	Second highest combined renewable/DSM generation share for 2020
Secondary Measures			
5th Percentile PVRR	Ranked second under the $0, Medium and averaged CO_2 tax scenarios; ranked fourth under the Low to Very High CO_2 tax scenario (Ranked fourth to seventh among all 14 core case portfolios)	Ranked first under the Medium and averaged CO_2 tax scenarios; ranked second under the Low to Very High CO_2 tax scenario, and third under the $0 CO_2 tax scenario (Ranked fourth or fifth among all 19 core case portfolios)	Ranked third under the Medium and averaged CO_2 tax scenarios; ranked fourth under the $0 tax scenario and fifth under the Low to Very High CO_2 tax scenario (Ranked sixth to eighth among all 19 core case portfolios)
Production Cost Standard Deviation	Not among the top three portfolios	Not among the top three portfolios	Ranked first under the $0 CO_2 tax scenario; ranked second under the averaged $0 CO_2 tax scenario; ranked third under the Medium and Low to Very High CO_2 tax scenarios

Deterministic Risk Assessment

PacifiCorp selected the Case 1 and Case 3 portfolios for deterministic risk assessment. Table 8.9 reports the deterministic PVRR results of running each portfolio through the System Optimizer model with the 10 combinations of CO_2 tax and natural gas price assumptions.

The reason that the Case 7 portfolio was excluded was because resource differences between this portfolio and the Case 3 portfolio were relatively small, primarily limited to the amount of DSM—35 MW more DSM in Case 7—and the timing and location of out-year growth resources (see Table 8.10a). In contrast, the Case 1 and Case 3 portfolios exhibit more significant resource differences; specifically a one-year shift in the timing of the first CCCT, 100 MW more DSM in Case 3, and a 50 MW biomass plant in Case 1 that was not included in Case 3 (Table 8.10b).

As shown in Table 8.9, the PVRR for the Case 3 portfolio is lower than that for the Case 1 portfolio under all but the Case 1 definition.

Table 8.9 – Deterministic PVRR Comparison for Case 1 and Case 3 Portfolios

Core Case	CO_2 cost (2015$/ton)	Natural gas cost	PVRR (millions)		Difference, Case 1 less Case 3
			Portfolio Case 1	Portfolio Case 3	
1	None ($0)	Medium	$30,936	$30,978	(42)
3	Medium ($19)	Low	$39,752	$39,581	172
4	High ($25)	Low	$44,717	$44,651	65
5	Low to very high ($12)	Low	$40,443	$40,398	46
7	Medium ($19)	Medium	$41,099	$41,074	25
8	High ($25)	Medium	$46,284	$46,221	63
9	Low to very high ($12)	Medium	$41,869	$41,815	54
11	Medium ($19)	High	$42,398	$42,337	60
12	High ($25)	High	$47,548	$47,456	92
13	Low to very high ($12)	High	$43,226	$43,142	83

Minimum	$30,936	$30,978
Maximum	$47,548	$47,456
Mean	$41,827	$41,765

Average of medium CO_2 cases	$41,083	$40,997
Average of high CO_2 cases	$46,183	$46,110
Average of low to very high CO_2 cases	$41,846	$41,785

Table 8.10 – Portfolio Resource Differences, Top Three Portfolios

Table 8.10a - Case 7 less Case 3 Resource Comparison

		Capacity, MW																						Resource Totals 2/	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year
East																									
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.3)	(0.4)	-	-	-	-	-	-	(2)
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	(0.8)	(0.8)	(0.8)	(0.8)	-	-	-	-	-	-	-	-	-	-	(3)	(3)
	DSM, Class 1 Total	-	-	9.2	(9.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9	-	-	(0)	5
	DSM, Class 2 Total	-	-	1.4	(0.8)	(0.2)	0.6	-	3.1	2.0	0.2	1.5	(4.2)	4.9	1.1	1.3	1.7	1.7	2.2	-	-	-	-	4	17
	FOT Mead Q3 HLH	-	-	-	-	-	-	-	(3.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)
	FOT Utah Q3 HLH	-	-	(9.9)	-	-	(0.8)	-	-	(7.9)	(7.7)	-	-	-	-	-	-	-	-	-	-	-	-	(26)	(26)
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	(0.1)	31.1	119.6	78.9	(13.4)	(82.9)	(9.5)	(85.2)	(36.5)	(2.1)	-	0
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31.6	(167.8)	(67.5)	17.4	186.3	N/A	(0)
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	52.8	4.8	(265.2)	-	26.7	(149.2)	327.9	N/A	-
West																									
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	(0.3)	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	3.6	-	-	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2 Total	-	-	0.3	0.2	0.6	0.4	0.5	0.6	0.6	0.6	0.1	-	1.4	1.5	1.2	1.3	1.3	1.0	0.9	0.2	0.4	0.4	4	13
	Micro Solar - Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	1.3	1.3	0.3	0.3	1.0	-	-	-	-	-	-	4
	FOT MidColumbia Q3 HLH	-	-	-	-	-	-	(1.0)	-	-	-	(8.3)	-	313.5	330.9	-	-	-	-	-	-	-	-	(1)	32
	FOT Mid-Columbia Q3 HLH - 10% Price Premium	-	-	-	-	(0.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(52.2)	(130.7)	(1.0)	177.2	(2.5)	5.1	(27.4)	(1.4)	N/A	(3)
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(18.4)	-	-	(720.9)	N/A	(74)
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	(318.1)	(368.6)	(77.8)	(10.9)	(2.4)	125.3	183.9	101.6	176.2	190.7	N/A	0

Table 8.10b - Case 1 less Case 3 Resource Comparison

		Capacity (MW)																				Resource Totals 2/	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	CCCT F 2x1 Utah North)	-	-	-	-	(597.0)	597.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	(13.5)	(5.1)	1.6	3.9	13.6	2.0	1.5	-	4
	CHP - Reciprocating Engine	-	-	-	0.8	0.8	-	(0.8)	(0.8)	(0.8)	(0.8)	-	-	-	-	-	-	-	-	-	-	(2)	(2)
	DSM, Class 1 Total	-	-	-	3.2	-	-	(4.9)	-	-	(5.4)	-	-	-	-	-	-	-	4.9	-	-	(7)	(2)
	DSM, Class 2 Total	-	-	(0.4)	1.8	19.0	(7.5)	(7.4)	(10.5)	(11.3)	(17.3)	(1.1)	(5.1)	(5.1)	(4.8)	(4.2)	(4.3)	(5.9)	(6.4)	(7.1)	(7.4)	(34)	(85)
	Micro Solar - Water Heating	-	-	-	-	-	-	-	-	(0.3)	(0.3)	(2.6)	(2.6)	(2.6)	(0.3)	-	-	-	-	-	-	(1)	(9)
	FOT Mead Q3 HLH	-	-	-	-	99.1	(23.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	FOT Utah Q3 HLH	-	-	-	(17.2)	200.0	-	(53.5)	(44.1)	-	(9.1)	-	-	-	-	-	-	-	-	-	-	76	76
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	1.8	2.3	83.2	34.9	16.6	(47.8)	14.2	(72.4)	(33.5)	0.8	-	0
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11.7)	(80.8)	(170.7)	(6.2)	269.5	N/A	(0)
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	63.9	6.0	(204.0)	155.7	(151.0)	(133.6)	263.0	N/A	-
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35.0)	-	-	-	-	-	-	(35)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Utility Biomass	-	-	-	-	50.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Reciprocating Engine	-	-	-	0.3	0.3	-	-	-	-	(0.3)	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 Total	-	-	-	10.0	-	-	(6.4)	-	-	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2 Total	2.1	-	-	0.4	0.4	(1.2)	(1.2)	(1.7)	(2.2)	(2.4)	(0.3)	(0.4)	(0.6)	(0.6)	(0.7)	(0.5)	(0.5)	(1.2)	(1.1)	(1.1)	(6)	(13)
	Micro Solar - Water Heating	-	-	-	-	-	(0.8)	(0.5)	(0.8)	(0.8)	(0.8)	-	-	-	-	1.0	-	-	-	-	-	(4)	(3)
	FOT MidColumbia Q3 HLH	-	-	-	-	101.1	-	-	-	(33.7)	-	309.3	330.9	-	-	-	-	-	-	-	-	7	35
	FOT Mid-Columbia Q3 HLH - 10% Price Premium	-	-	(1.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT West Main Q3 HLH	-	-	-	-	50.0	(47.8)	-	-	-	-	-	33.4	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	0	22
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	(52.2)	(130.7)	(26.9)	140.4	(94.9)	174.5	1.5	(11.8)	N/A	0
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(279.1)	37.4	-	(720.9)	N/A	(96)
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	(318.1)	(368.6)	(77.8)	(10.9)	(4.4)	117.7	284.1	181.6	176.8	210.3	N/A	19

1/ Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

2/ Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Preliminary Preferred Portfolio Selection

Based on the PVRR cost/risk, CO_2 emissions, supply reliability measures, and deterministic risk assessment, the Case 3 specification resulted in the best cost/risk portfolio.

Acquisition Risk Assessment

Combined-cycle Combustion Turbine Resource Timing

PacifiCorp evaluated the deferral value of moving the dry-cooled CCCT proxy resource (assumed to be located at the Currant Creek site) from 2015 to 2016. As noted in the methodology chapter, the portfolios developed for stochastic production cost simulation do not isolate the impact of CCCT acquisition timing. Also, while all portfolios included a CCCT in 2014, one of the preferred portfolio candidates (Case 1) included a second CCCT in 2016, indicating that the decision to acquire the CCCT in 2015 or 2016 is driven by economic considerations. From rate impact, corporate budgeting, and procurement process perspectives, acquiring two CCCT plants in a two-year span is problematical, and the Company would not pursue that acquisition path unless there was strong justification from an economics or need perspective.[68] The stochastic production cost analysis described below was intended to help determine if economics justified CCCT acquisition in 2015.

Using the original Case 3 portfolio under the \$19 CO_2 tax scenario, PacifiCorp developed a portfolio with the Currant Creek 2 dry-cooled CCCT delayed one year to 2016, and included 597 MW of third quarter front office transaction products to fill the resource gap: 100 MW from Mead, 200 MW from Utah, 101 MW from Mid-Columbia 101, and 196 MW from California-Oregon Border (COB). These FOT additions are well below the limits specified for the market hubs. Table 8.11 reports the stochastic PVRR results. As indicated, the one-year CCCT deferral to 2016 results in a \$14.7 million PVRR benefit. While variable costs increase due to FOT acquisition, this cost increase is more than offset by the reduction in capital and fixed costs.

In terms of upper-tail cost impact, deferring the CCCT resource by one year decreased the stochastic upper-tail mean PVRR by \$19.1 million (\$40.341 billion versus \$40.360 billion).

[68] For example, if the Company could not meet its target planning reserve margin with alternative, more cost-effective resources as determined by then-current needs assessment and portfolio modeling.

Table 8.11 – Dry-cooled CCCT, 2015 to 2016 PVRR Deferral Value

Cost Component ($ Millions)	Dry-cooled CCCT in 2015 (Case 3 Portfolio)	Dry-cooled CCCT in 2016 (Case 3 Portfolio)	Currant Creek II 2016 less Currant Creek II
Variable Costs			
Fuel & O&M	15,729.2	15,695.6	(33.6)
Emission Cost	7,424.5	7,427.7	3.3
FOT's & Long Term Contracts	3,955.8	4,035.7	79.8
Demand Side Management	$3,670	$3,670	-
Renewables	$848	$848	0.03
System Balancing Sales	(5,936.6)	(5,957.4)	(20.8)
System Balancing Purchases	3,168.3	3,160.8	(7.5)
Energy Not Served	137.0	137.4	0.4
Dump Power	(116.8)	(116.9)	(0.1)
Reserve Deficiency	2.4	2.5	0.0
Total Variable Costs	28,881.8	28,903.4	21.6
Capital and Fixed Costs	5,953.6	5,917.3	(36.3)
Total PVRR	34,835.4	34,820.7	(14.7)

Based on these stochastic PVRR results, the Company concluded that the 2011 IRP preferred portfolio should reflect a second CCCT added in 2016.

Geothermal Resource Acquisition

Case 3 includes 105 MW of geothermal resources. As indicated at the December 15, 2010 IRP public input meeting, a decision to pursue additional geothermal resources will be dependent on a clear signal that legislators and regulators will support full recovery of resource development costs. In the absence of enabling cost recovery legislation and pre-approval of cost recovery from regulators, the Company is viewing geothermal acquisition of up to 105 MW as representing an alternate resource procurement path to be explored for the next IRP if progress is made regarding cost recovery.

Combined Economic Impact of the CCCT Deferral and Geothermal Resource Exclusion

Based on the results of the CCCT deferral study and geothermal resource situation, PacifiCorp developed a new System Optimizer portfolio using the Case 3 input assumptions along with exclusion of geothermal resources as model options. To compel the model to defer the second CCCT from 2015 to 2016, the Company increased the limit on Utah FOT from 200 MW to 250 MW, which is in line with the Utah market purchase depth assumed for the 2008 IRP. The Company also made one additional resource change: it incorporated corrected capacity potentials for the commercial/industrial sector curtailment DSM product received from Cadmus after the completion of portfolio development. The potentials were effectively doubled. For example, the 2011 Utah potential increased from 21.5 MW to 43.0 MW.

The Company simulated the resulting System Optimizer portfolio with the PaR model to compare with the original Case 3 PVRR results based on the $19 CO_2 tax scenario. Table 8.12 reports the stochastic PVRR comparison with the original Case 3 portfolio. As shown, the revised portfolio results in a $23.6 million stochastic mean PVRR improvement over the original Case 3 portfolio. The stochastic upper-tail mean PVRR increased by $7 million.

Table 8.12 – PVRR Comparison, Preliminary Preferred Portfolio vs. Revised Preferred Portfolio

Cost Component ($ Millions)	Preliminary Preferred Portfolio	Preliminary Preferred Portfolio with 2016 CCCT, no geothermal, and increased Commercial Curtailment DSM	Difference
Variable Costs			
Fuel & O&M	$15,729.2	$15,991.6	$262.4
Emission Cost	7,424.5	7,433.0	8.6
FOT's & Long Term Contracts	3,955.8	4,044.7	88.9
Demand Side Management	3,670	3,684	13.69
Renewables	$848	$656	(191.92)
System Balancing Sales	(5,936.6)	(6,058.3)	(121.7)
System Balancing Purchases	3,168.3	3,089.4	(78.9)
Energy Not Served	137.0	143.1	6.1
Dump Power	(116.8)	(116.4)	0.4
Reserve Deficiency	2.4	1.9	(0.5)
Total Variable Costs	28,881.8	28,868.7	(13.1)
Capital and Fixed Costs	5,953.6	5,943.1	(10.4)
Total PVRR	34,835.4	34,811.8	(23.6)

Government Compliance Risk Mitigation and Long Term Public Interest Considerations

A key risk factor affecting resource strategies for the IRP is regulatory compliance uncertainty in the areas of renewable energy acquisition and greenhouse gas emission control. In this section, the Company assesses the quantity and timing of renewables appropriate for addressing long-term regulatory risk exposure. While the action plan and acquisition path analysis in Chapter 9 make provision for a range of renewable and emerging technologies, the Company is best positioned to exploit wind resource potential, and thus focuses on this resource from a strategic positioning standpoint. As noted in Chapter 7, the Company focuses on mitigation of upper-tail (worst-case) cost outcomes as the suitable criterion for evaluating risk management benefits of renewables. This criterion also recognizes risk management benefits stemming from less portfolio exposure to volatile fuel prices, with subsidiary benefits arising from reduced pollution emissions and water usage—the later becoming an increasing concern in the western U.S. This section also summarizes sensitivity analysis of the preliminary preferred portfolio with respect to the Waxman-Markey renewable energy targets and extension of the renewables PTC to 2020.

Risk-Mitigating Renewables

Table 8.13 shows the derivation of the optimal risk-mitigating wind quantity based on the evaluation of stochastic upper-tail mean PVRR performance across the 19 core portfolios. The wind quantity selected was 2,100 MW. The gray highlighted cells in the table indicate the three top-performing portfolios based on upper-tail mean PVRR for each CO_2 tax scenario. Since geothermal has been excluded from the preferred portfolio, PacifiCorp then converted geothermal capacity to an equivalent amount of wind capacity using the ratio of the resource capacity factors. The resulting geothermal-equivalent wind capacity for each portfolio is shown in the fourth and ninth columns. The two smaller tables at the bottom report the average wind capacity (wind plus geothermal-equivalent wind) across the three top-performing portfolios.

Table 8.13 – Derivation of Wind Capacity for the Preferred Portfolio

	Low to Very High CO_2 Tax					\$19/ton CO_2 tax				
Portfolio	Wind (MW)	Geothermal (MW)	Geothermal-equivalent Wind (MW) 1/	Upper Tail Mean PVRR (\$ Millions)	Rank	Wind (MW)	Geothermal (MW)	Geothermal-equivalent Wind (MW) 1/	Upper Tail Mean PVRR (\$ Millions)	Rank
1	143	185	481	41,748	11	143	185	481	40,465	8
2	0	80	208	41,897	14	0	80	208	40,542	9
3	139	220	572	41,639	8	139	220	572	40,360	6
4	136	220	572	41,801	13	136	220	572	40,667	14
5	227	185	481	41,685	9	227	185	481	40,653	12
6	305	220	572	41,229	3	305	220	572	40,205	4
7	137	220	572	41,578	7	137	220	572	40,342	5
8	50	255	663	41,929	15	50	255	663	40,747	15
9	418	395	1027	41,709	10	418	395	1027	40,666	13
10	760	605	1573	41,052	2	760	605	1573	40,021	2
11	100	535	1391	41,787	12	100	535	1391	40,592	11
12	2160	535	1391	41,417	6	2160	535	1391	40,452	7
13	1700	535	1391	41,270	4	1700	535	1391	40,576	10
14	1300	675	1755	40,886	1	1300	675	1755	39,816	1
15	139	220	572	41,375	5	139	220	572	40,197	3
16	50	255	663	43,469	17	50	255	663	41,519	17
17	2600	535	1391	45,819	18	2600	535	1391	43,692	19
18	408	220	572	46,097	19	408	220	572	42,791	18
19	1260	0	0	42,276	16	1260	0	0	41,203	16

1/ Based on the ratio of the geothermal resource capacity factor (90%) to the wind capacity factor (35%).

Average Capacity of the Top Three Portfolios based on Upper-tail Mean PVRR (MW)

Wind	Geothermal-equivalent Wind	Total
788	1,300	2,088

Wind	Geothermal-equivalent Wind	Total
733	1,300	2,033

Wind Quantity Impact of Alternative Renewable Policy Assumptions

PacifiCorp generated two alternative versions of the preliminary preferred portfolio by running System Optimizer with the preferred portfolio set-up along with modified renewable policy assumptions. This portfolio development exercise was used to help allocate the 2,100 MW of wind on an annual basis, as well as support the acquisition path analysis outlined in Chapter 9. The first portfolio was developed by replacing the base RPS constraints (system percentage constraints based on current state RPS requirements) with ones reflecting the higher Waxman-Markey targets.

The second portfolio was developed by then layering in renewable resources with costs that reflect an extension of the renewable PTC to 2020.

Table 8.14 compares the preliminary preferred portfolio wind quantities with the resulting incremental wind quantities selected for the two alternative renewable policy portfolios. For example, 932 MW of additional wind is needed to comply with the Waxman-Markey RPS portfolio, resulting in a total wind amount of 1,631 MW. Extending the federal PTC then increases the amount of wind by an additional 97 MW for a total of 1,728 MW.

Table 8.14 – Wind Additions under Alternative Renewable Policy Assumptions

	Preliminary Preferred Portfolio	Incremental Wind, Waxman-Markey RPS Portfolio			Incremental Wind, Waxman-Markey RPS Portfolio plus PTC Extension to 2020		
Year	East Capacity (MW)	East Capacity (MW)	West Capacity (MW)	Total Capacity (MW)	East Capacity (MW)	West Capacity (MW)	Total Capacity (MW)
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	200	200	0	147	147
2016	0	0	0	0	147	53	200
2017	0	171	0	171	200	0	200
2018	0	200	0	200	200	0	200
2019	0	200	0	200	200	0	200
2020	142	58	0	58	58	0	58
2021	200	(185)	0	(185)	(185)	0	(185)
2022	31	43	0	43	41	0	41
2023	0	36	0	36	26	0	26
2024	51	(3)	0	(3)	(11)	0	(11)
2025	200	(179)	0	(179)	(175)	0	(175)
2026	21	93	0	93	80	0	80
2027	8	40	0	40	38	0	38
2028	9	83	0	83	58	0	58
2029	4	37	0	37	34	0	34
2030	34	140	0	140	119	0	119
TOTAL	699	732	200	932	829	200	1,029

Given that wind is added in every year for these alternative portfolios, and some front-loading is necessary to comply with a federal RPS requirement along the lines of the Waxman-Markey targets, PacifiCorp distributed the 2,100 MW of wind into the annual wind schedule shown in Table 8.15. Annual amounts were kept relatively level from year to year, recognizing the need for rate and capital spending stability. Actual wind acquisition will be determined as an outcome of government mandates and constraints, transmission availability, technology costs, and the Company's renewables procurement process.

Table 8.15 –Wind Capacity Schedule

Year	Wyoming Wind (MW)
2018	300
2019	300
2020	200
2021	200
2022	200
2023	200
2024	200
2025	100
2026	100
2027	100
2028	100
2029	100
2030	-

Preferred Portfolio

PacifiCorp developed the preferred portfolio by running System Optimizer with the preliminary preferred portfolio set-up along with the fixed wind additions in Table 8.15. This modeling step ensures that the portfolio is balanced on a capacity and energy basis with the wind schedule in place. Figure 8.11 summarizes the steps leading from final screening to the preferred portfolio.

Figure 8.11 – Preferred Portfolio Derivation Steps

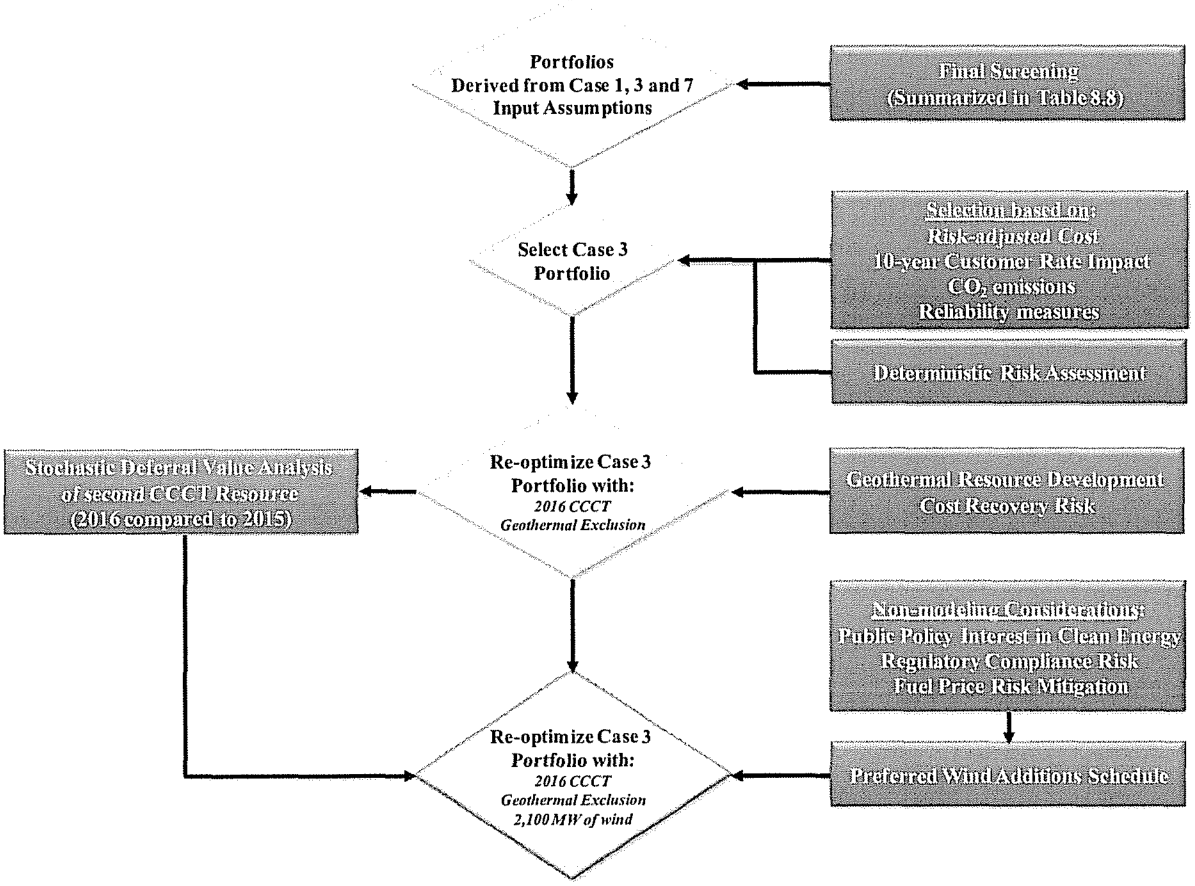


Table 8.16 provides the detailed view of the preferred portfolio resources, while Table 8.17 presents the preferred portfolio capacity load & resource balance. (Note that wind capacity in Table 8.17 reflects capacity contribution at the time of peak annual load and not installed capacity.) Figures 8.12 and 8.13 show energy and capacity resource mixes, respectively, for representative years 2011 and 2020. The energy mix charts use the medium natural gas price scenario, while the 2020 chart uses the medium CO_2 tax scenario ($24/ton in 2020). As noted in chapter 3, the renewable energy capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements. Figure 8.14 graphically shows how PacifiCorp's capacity deficit is met through existing and IRP preferred portfolio resources.

Table 8.16 – Preferred Portfolio, Detail Level

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals 1/ 10-year	20-year
East																							
	CCCT F 2x1 (Utah North, Utah South)	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H (Utah South)	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	300	300	200	200	200	200	200	100	100	100	100	100	-	800	2,100
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	DSM, Class 1, Utah Cool Keeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Idaho DLC-Irrigation	-	-	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	20	22
	DSM, Class 1, Utah, Curtailment	-	43	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	71	71
	DSM, Class 1, Utah, DLC-Residential	-	22	-	-	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	85
	DSM, Class 1, Utah, DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	3
	DSM, Class 1 Total	6	70	-	20	91	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	187	191
	DSM, Class 2, Idaho	1	2	2	3	3	4	4	4	4	5	5	5	6	6	6	6	6	6	6	6	33	11
	DSM, Class 2, Utah	42	47	39	40	41	44	45	46	48	50	48	55	51	53	53	57	52	55	54	56	442	976
	DSM, Class 2, Wyoming	3	4	5	5	6	6	7	8	8	8	10	10	12	15	16	20	24	28	35	37	60	267
	DSM, Class 2 Total	47	53	46	48	51	54	56	58	60	63	62	70	69	74	75	84	82	89	95	99	536	1,334
	Micro Solar - Water Heating	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	FOT Mead Q3 HLH	-	168	264	264	99	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82	41
	FOT Utah Q3 HLH	200	200	204	26	250	-	72	217	-	245	-	-	-	-	-	-	-	-	-	-	141	71
	FOT Mona Q3 HLH	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
	Growth Resource, Goshen ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149	293	108	215	232	3	N/A	100
	Growth Resource, Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	201	211	303	261	N/A	100
	Growth Resource, Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	206	55	346	392	-	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	DSM, Class 1, California, DLC-Irrigation	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Oregon, DLC-Irrigation			13																			
	DSM, Class 1, Oregon, Curtailment	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36	36
	DSM, Class 1, Washington, DLC-Irrigation	-	-	2	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1 Total 2/	-	-	57	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	63	63
	DSM, Class 2, Washington	7	8	8	8	8	8	8	8	8	8	9	10	10	10	10	8	8	8	8	9	79	170
	DSM, Class 2, California	1	1	1	1	1	1	1	1	1	2	1	1	2	2	2	2	2	2	2	2		
	DSM, Class 2, Oregon	53	53	56	61	62	61	60	52	52	52	52	52	52	52	52	52	44	36	36	36	562	1,028
	DSM, Class 2 Total	61	61	65	70	71	70	70	62	62	62	63	63	64	65	65	63	54	46	46	46	653	1,228
	OR Solar Capacity Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Incentive Program Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heating	-	1.81	1.81	1.81	1.81	1.81	1.81	0.97	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	FOT COB Q3 HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	32
	FOT MidColumbia Q3 HLH	-	400	400	400	400	400	400	400	395	400	400	400	400	400	400	400	400	400	400	400	360	380
	FOT MidColumbia Q3 HLH, 10% price premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT Oregon Q3 HLH	-	50	50	50	50	50	50	50	-	50	-	50	50	50	50	50	50	50	50	50	40	43
	Growth Resource, Walla Walla WA	-	-	-	-	-	-	-	-	-	-	-	-	-	112	57	20	205	202	203	201	N/A	100
	Growth Resource, Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	252	-	-	748	N/A	100
	Growth Resource, Yakima WA	-	-	-	-	-	-	-	-	-	-	11	95	201	138	341	174	41	-	20	53	N/A	107
	Annual Additions, Long Term Resources	134	217	187	776	232	749	136	437	902	330	332	339	338	344	245	252	241	245	246	151		
	Annual Additions, Short Term Resources	350	1,240	1,429	1,190	1,149	775	822	967	695	995	711	845	951	1,000	1,296	1,467	1,613	1,725	1,900	2,015		
	Total Annual Additions	484	1,457	1,616	1,966	1,381	1,524	958	1,404	1,597	1,325	1,043	1,184	1,289	1,344	1,542	1,719	1,855	1,970	2,146	2,165		

1/ Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive. Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

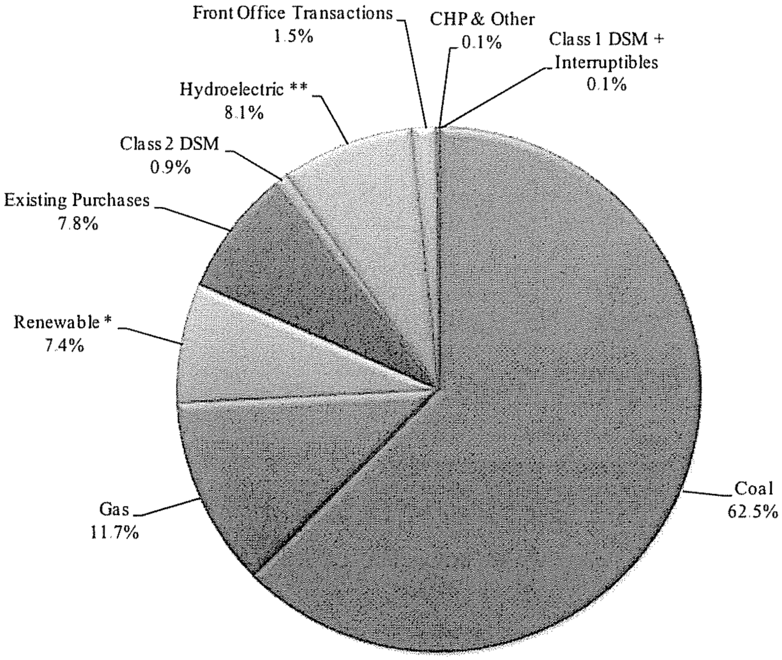
2/ PacifiCorp excluded from the portfolio new programs under a five-megawatt implementation feasibility threshold. The programs excluded consist of direct load control programs for Washingto, Oregon, and California.

Table 8.17 – Preferred Portfolio Load and Resource Balance (2011-2020)

Calendar Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
East										
Thermal	6,019	6,026	6,028	6,028	6,028	6,046	6,046	6,046	6,046	6,046
Hydroelectric	133	133	133	133	133	129	129	129	129	129
Class 1 DSM	324	329	329	329	329	329	329	329	329	329
Renewable	179	179	179	178	176	176	176	176	176	176
Purchase	655	705	604	304	304	283	283	283	283	283
Qualifying Facilities	152	187	206	206	207	206	207	207	206	206
Interruptible	281	281	281	281	281	281	281	281	281	281
Transfers	1,002	916	1,014	623	614	578	572	542	444	284
East Existing Resources	**8,745**	**8,755**	**8,774**	**8,083**	**8,071**	**8,028**	**8,022**	**7,992**	**7,894**	**7,734**
Combined Heat and Power	1	2	3	4	5	6	7	8	9	10
Class 1 DSM	0	65	65	85	176	176	176	176	176	176
Class 2 DSM	34	73	88	128	170	214	261	309	358	410
Front Office Transactions	200	368	618	590	649	325	372	517	300	545
Gas	0	0	0	625	625	1,222	1,222	1,222	1,697	1,697
Wind	0	0	0	0	0	0	0	8	21	28
East Planned Resources	**235**	**509**	**774**	**1,432**	**1,625**	**1,943**	**2,038**	**2,239**	**2,561**	**2,866**
East Total Resources	**8,980**	**9,264**	**9,548**	**9,515**	**9,696**	**9,972**	**10,060**	**10,232**	**10,455**	**10,600**
Load	7,184	7,344	7,566	7,805	8,009	8,201	8,377	8,544	8,712	8,896
Sale	758	997	1,045	745	745	745	659	659	659	659
East Obligation	**7,942**	**8,341**	**8,611**	**8,550**	**8,754**	**8,946**	**9,036**	**9,203**	**9,371**	**9,555**
Planning reserves (13%)	838	848	861	888	890	954	953	950	994	979
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	**909**	**918**	**932**	**959**	**960**	**1,024**	**1,024**	**1,020**	**1,064**	**1,049**
East Obligation + Reserves	**8,850**	**9,258**	**9,543**	**9,509**	**9,714**	**9,970**	**10,060**	**10,224**	**10,435**	**10,605**
East Position	**130**	**5**	**5**	**6**	(18)	**1**	**1**	**8**	**19**	(4)
East Reserve Margin	**15%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**
West										
Thermal	2,552	2,552	2,556	2,556	2,556	2,556	2,541	2,550	2,550	2,550
Hydroelectric	1,103	958	958	957	958	959	958	958	902	745
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Renewable	77	71	71	71	71	71	71	71	71	71
Purchase	856	247	331	226	221	225	255	269	285	242
Qualifying Facilities	136	136	136	136	136	136	136	136	136	136
Transfers	(1,003)	(918)	(1,015)	(623)	(615)	(578)	(573)	(542)	(446)	(286)
West Existing Resources	**3,721**	**3,046**	**3,037**	**3,323**	**3,327**	**3,368**	**3,389**	**3,442**	**3,498**	**3,458**
Combined Heat and Power	4	8	13	17	21	25	29	34	38	42
Class 1 DSM	0	0	62	62	72	72	72	72	72	72
Class 2 DSM	15	30	43	60	77	94	111	125	140	156
Front Office Transactions	150	871	811	600	500	450	450	450	395	450
Solar	2	3	5	6	7	7	7	7	7	7
West Planned Resources	**170**	**913**	**934**	**745**	**677**	**648**	**669**	**688**	**653**	**727**
West Total Resources	**3,892**	**3,959**	**3,971**	**4,068**	**4,004**	**4,017**	**4,058**	**4,130**	**4,151**	**4,185**
Load	3,266	3,374	3,395	3,448	3,491	3,541	3,584	3,650	3,666	3,713
Sale	290	258	258	258	158	108	108	108	108	108
West Obligation	**3,556**	**3,632**	**3,653**	**3,706**	**3,649**	**3,649**	**3,692**	**3,758**	**3,774**	**3,821**
Planning reserves (13%)	330	323	313	359	361	365	365	369	375	377
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	**336**	**329**	**319**	**365**	**368**	**372**	**371**	**376**	**381**	**384**
West Obligation + Reserves	**3,892**	**3,962**	**3,973**	**4,071**	**4,017**	**4,020**	**4,063**	**4,134**	**4,155**	**4,204**
West Position	(0)	(3)	(2)	(3)	(12)	(4)	(5)	(4)	(4)	(20)
West Reserve Margin	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**12%**
System										
Total Resources	**12,872**	**13,222**	**13,518**	**13,582**	**13,700**	**13,989**	**14,118**	**14,361**	**14,605**	**14,785**
Obligation	**11,497**	**11,973**	**12,264**	**12,256**	**12,403**	**12,595**	**12,728**	**12,961**	**13,145**	**13,376**
Reserves	**1,245**	**1,247**	**1,251**	**1,324**	**1,328**	**1,396**	**1,395**	**1,396**	**1,445**	**1,433**
Obligation + Reserves	**12,742**	**13,220**	**13,515**	**13,580**	**13,731**	**13,991**	**14,123**	**14,357**	**14,590**	**14,809**
System Position	**130**	**2**	**3**	**3**	(31)	(2)	(4)	**4**	**15**	(24)
Reserve Margin	**14%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**

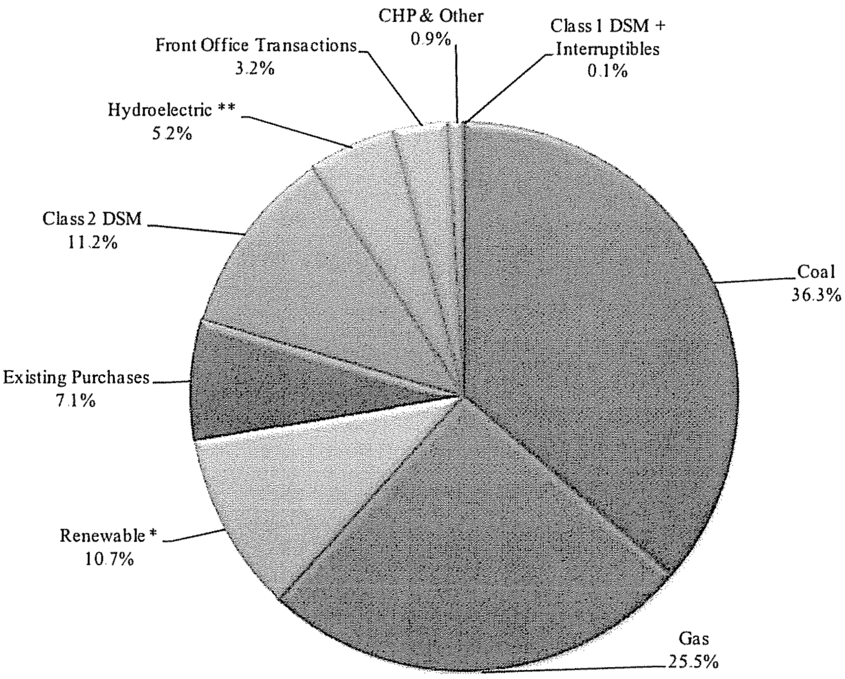
Figure 8.12 – Current and Projected PacifiCorp Resource Energy Mix for 2011 and 2020

2011 Resource Energy Mix with Preferred Portfolio Resources



* Renewable resources include wind, solar and geothermal. Renewable energy generation reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases

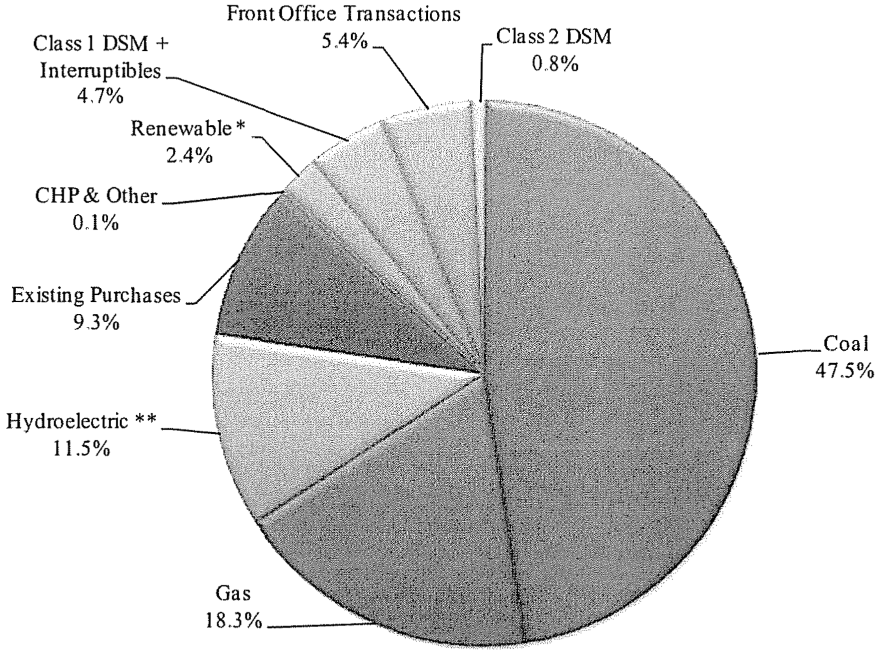
2020 Resource Energy Mix with Preferred Portfolio Resources
$24 CO_2 Tax (nominal dollars)



* Renewable resources include wind, solar and geothermal. Renewable energy generation reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements
** Hydroelectric resouces include owned, qualifying facilities and contract purchases.

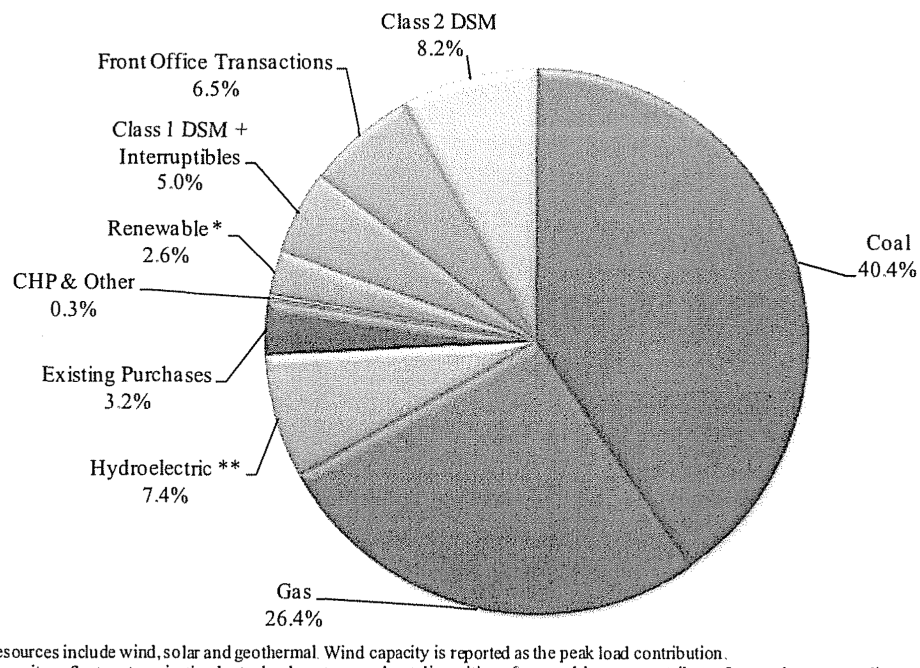
Figure 8.13 – Current and Projected PacifiCorp Resource Capacity Mix for 2011 and 2020

2011 Resource Capacity Mix with Preferred Portfolio Resources



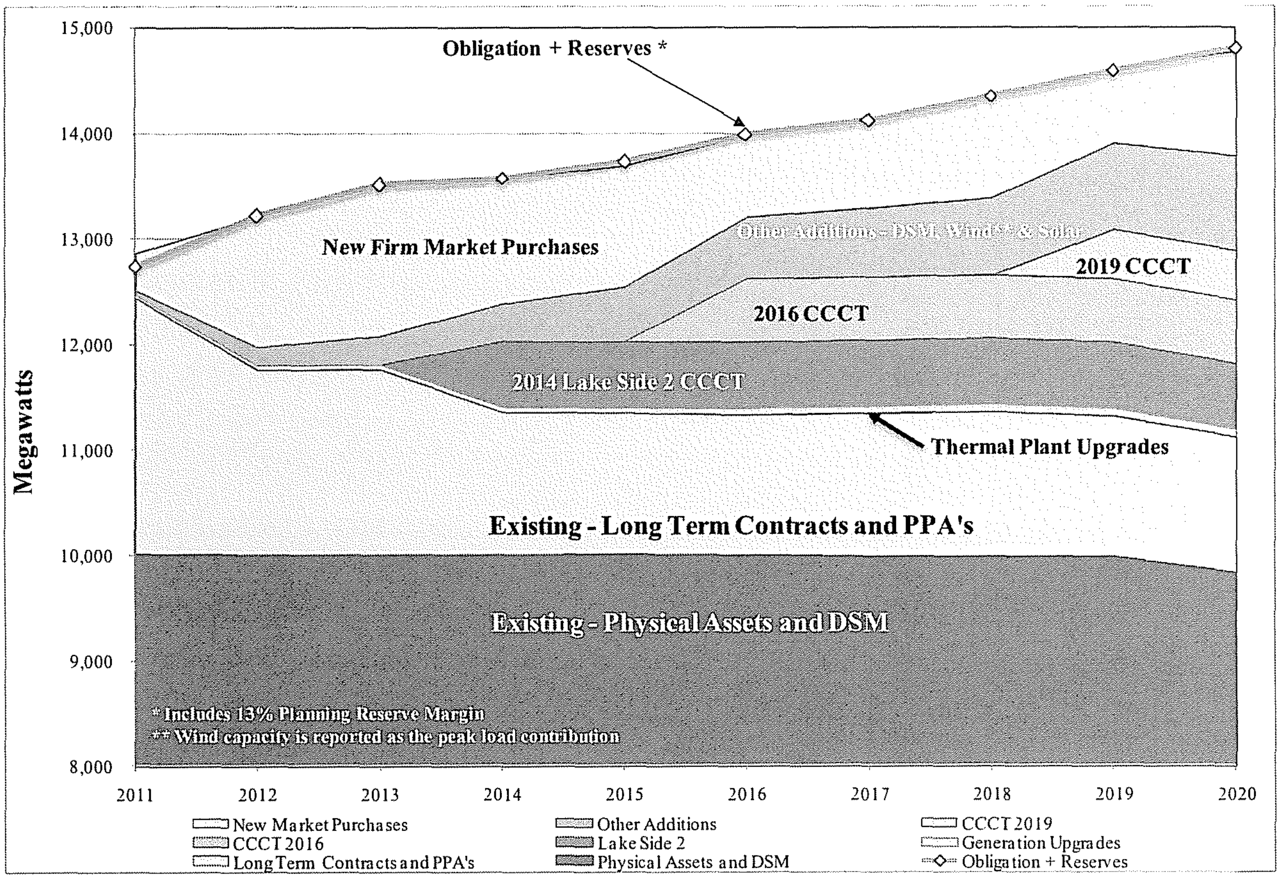
* Renewable resources include wind, solar and geothermal. Wind capacity is reported as the peak load contribution.
Renewable capacity reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases

2020 Resource Capacity Mix with Preferred Portfolio Resources



* Renewable resources include wind, solar and geothermal. Wind capacity is reported as the peak load contribution.
Renewable capacity reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases

Figure 8.14 – Addressing PacifiCorp's Peak Capacity Deficit, 2011 through 2020



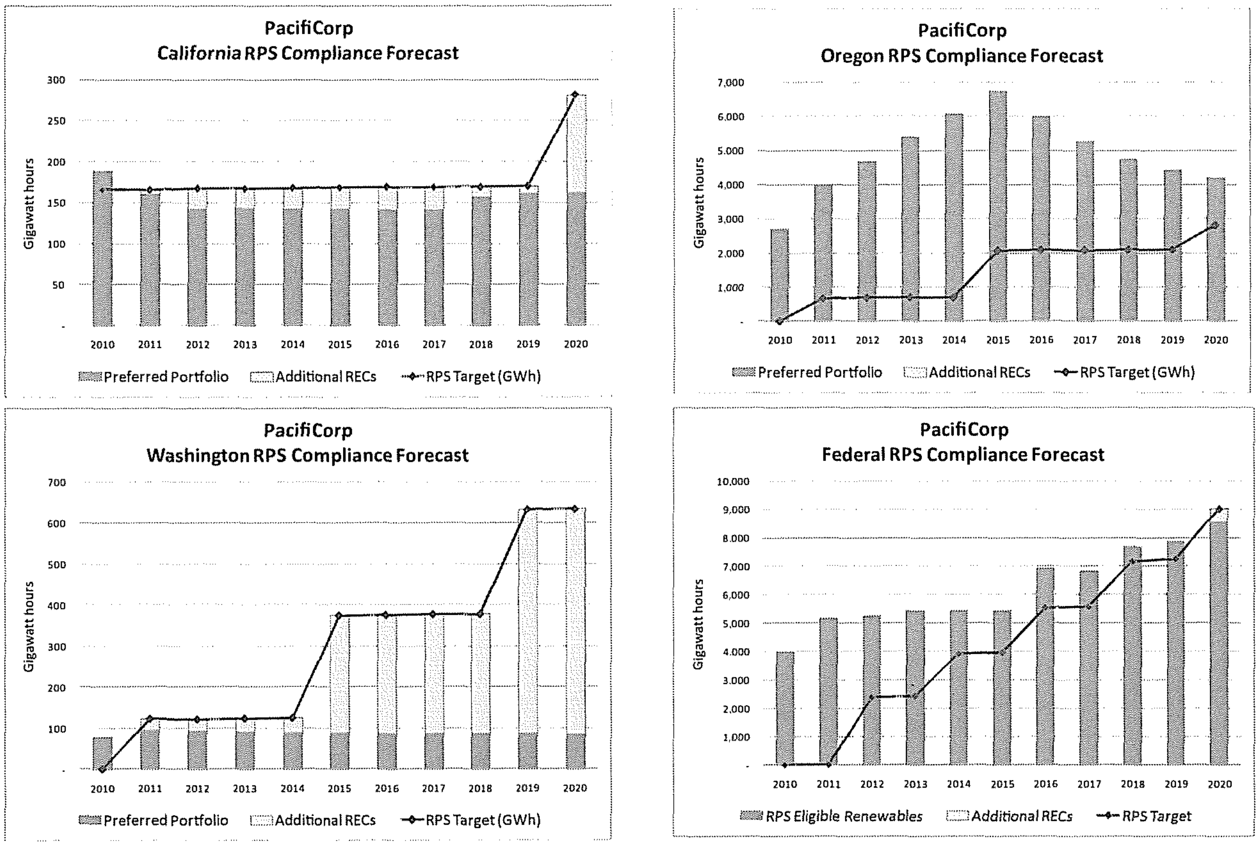
Preferred Portfolio Compliance with Renewable Portfolio Standard Requirements

Figure 8.15 below shows PacifiCorp's forecasted RPS compliance position for the California, Oregon, and Washington[69] programs, along with a federal RPS program scenario[70], covering the period 2010 through 2020 based on the preferred portfolio. Utah's RPS goal is tied to a 2025 compliance date, so the 2010-2020 position is not shown below. However, PacifiCorp meets the Utah 2025 state target of 20 percent based on eligible Utah RPS resources, and has significant levels of banked RECs to sustain continued future compliance.

As an IRP planning assumption, PacifiCorp anticipates utilizing flexible compliance mechanisms such as banking and/or tradable RECs where allowed, to meet the RPS requirements.

[69] The Washington RPS requirement is tied to January 1st of the compliance year, beginning in 2012.
[70] The forecasted federal RPS position is a scenario based on the Waxman-Markey legislation with targets of 6 percent beginning in 2012, 9.5 percent in 2014, 13 percent in 2016, 16.5 percent in 2018, and 20 percent in 2020.

Figure 8.15 – Annual State and Federal RPS Position Forecasts using the Preferred Portfolio

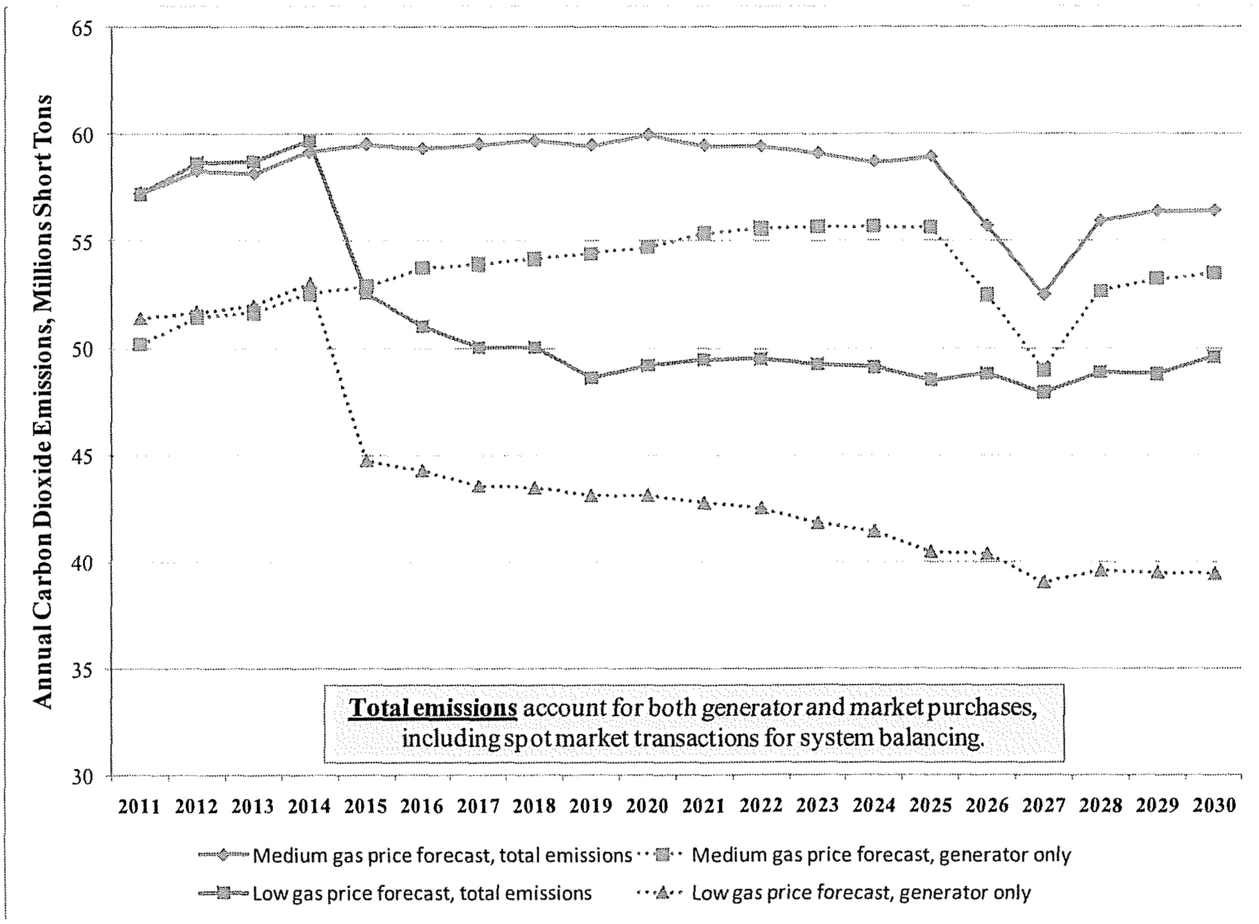


Preferred Portfolio Carbon Dioxide Emissions

Cumulative generator CO_2 emissions by 2030 for the preferred portfolio under the medium CO_2 tax scenario ($19/ton beginning in 2015) was 815 million tons, compared to 838 million tons for the preliminary preferred portfolio, and 821 million tons for the core case portfolio with the lowest generator emissions among those selected for the final screening (Case 6 portfolio). These emission quantities are reported by the PaR production cost model.

Regarding CO_2 emission reduction trends, near-term reductions are driven by plant dispatch changes in response to assumed CO_2 prices. In the longer term, cumulative energy efficiency and wind additions help offset emissions stemming from resource growth needed to meet load obligations. Figure 8.16 illustrates these emission trends for the preferred portfolio through 2030 under both the medium and low natural gas price scenarios. Total system emissions and generator-only emission trends are also shown.

Figure 8.16 – Carbon Dioxide Generator Emission Trend, \$19/ton CO_2 Tax



Sensitivity Analyses

System Optimizer Sensitivity Cases

Coal Utilization Cases

PacifiCorp conducted five System Optimizer case runs that incorporated incremental costs associated with existing coal plants, as well as replacement CCCT resources that includes costs associated with existing plant decommissioning/demolition, coal contract liquidated damages, and remaining coal plant book value recovery. Chapter 7 describes the modeling approach and cost categories addressed in the study.

Table 8.18 shows the disposition of coal units in each of the System Optimizer case runs. No coal units are replaced under medium case assumptions. Low natural gas prices combined with high CO_2 tax level assumptions are necessary to prompt coal unit replacements and high CO_2 tax levels combined with low gas prices prompted the model to select a small number of replacement CCCTs beginning in 2025.

Table 8.18 – Disposition of Coal Units for the Coal Utilization Cases

Case	20	21	22	23	24
CO_2 Cost	Medium	Medium	High	High	CO_2 Hard Cap
Natural Gas Cost	Medium	Low	Medium	Low	Medium
Coal Unit CCCT Replacements and Replacement Years	None	Two units replaced (2030)	One unit replaced (2030)	One unit replaced (2025) Two units replaced (2026) One unit replaced (2030)	One unit replaced (2026) Two units replaced (2027)

Figures 8.17 through 8.21 show the average annual capacity factors by resource type—coal, CCCT, and SCCT—for each of the cases. The capacity factors are weighted by unit megawatt capacity, and reflect both existing and future resources, including any replacement CCCTs.

Figure 8.17 – Gas and Coal Plant Utilization Trends, Case 20

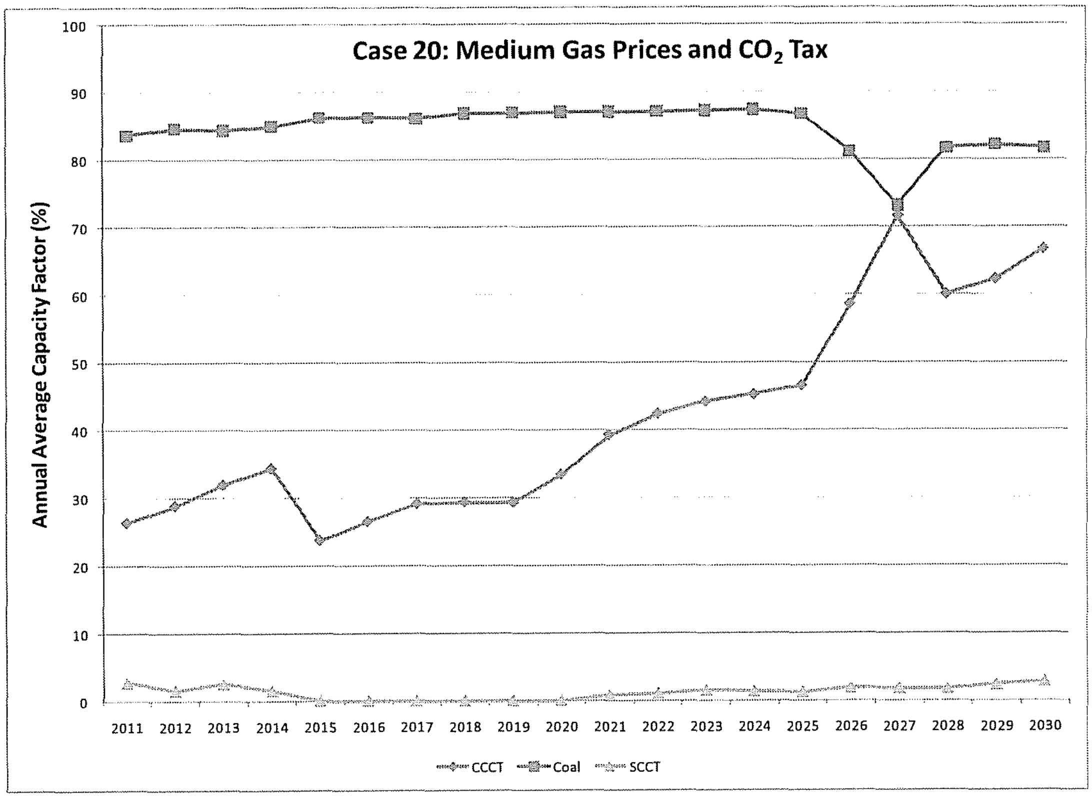


Figure 8.18 – Gas and Coal Plant Utilization Trends, Case 21

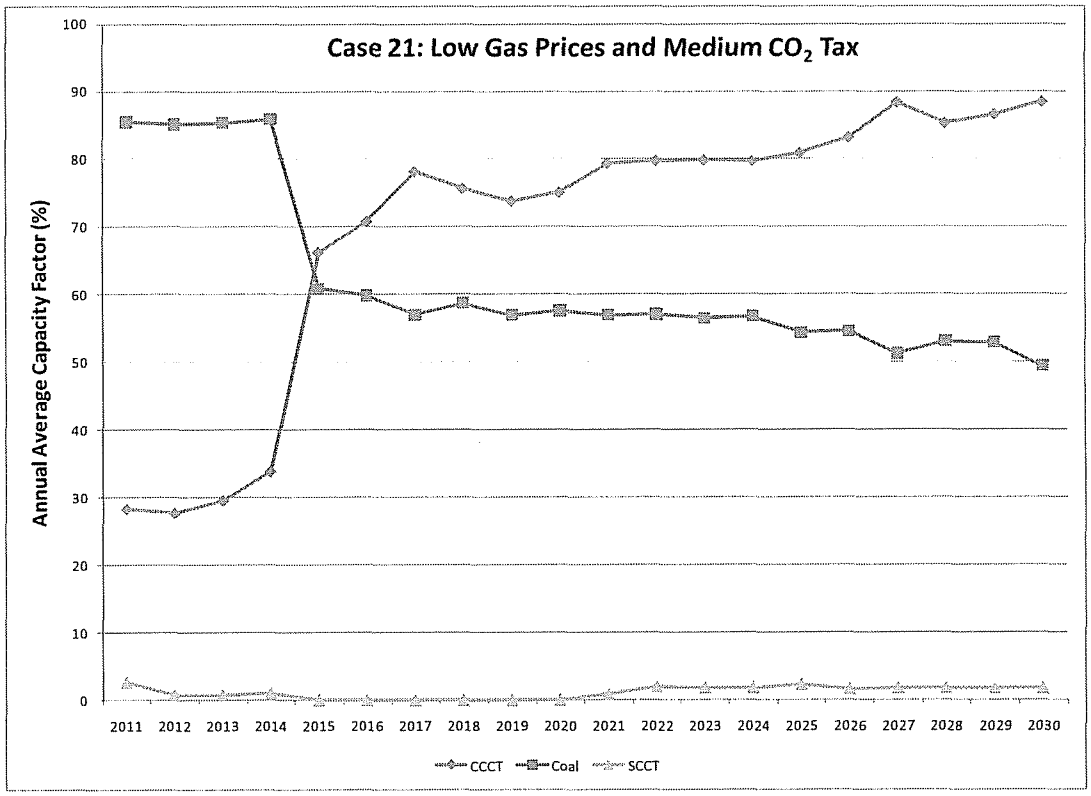


Figure 8.19 – Gas and Coal Plant Utilization Trends, Case 22

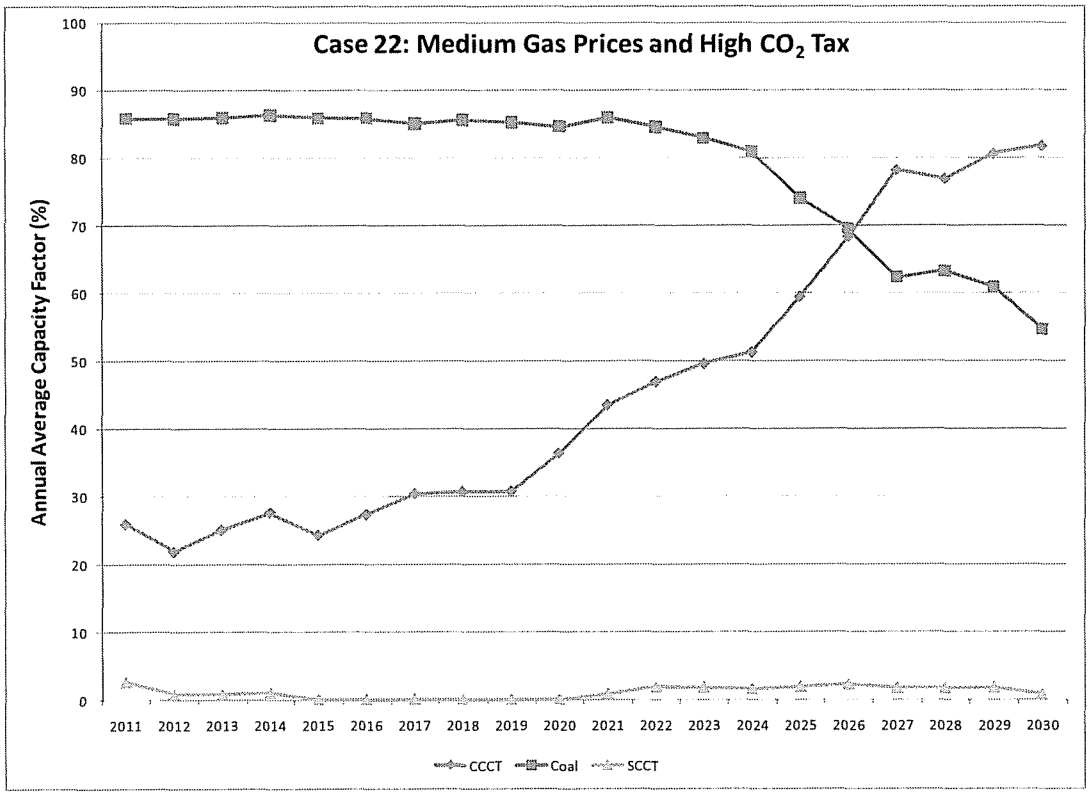


Figure 8.20 – Gas and Coal Plant Utilization Trends, Case 23

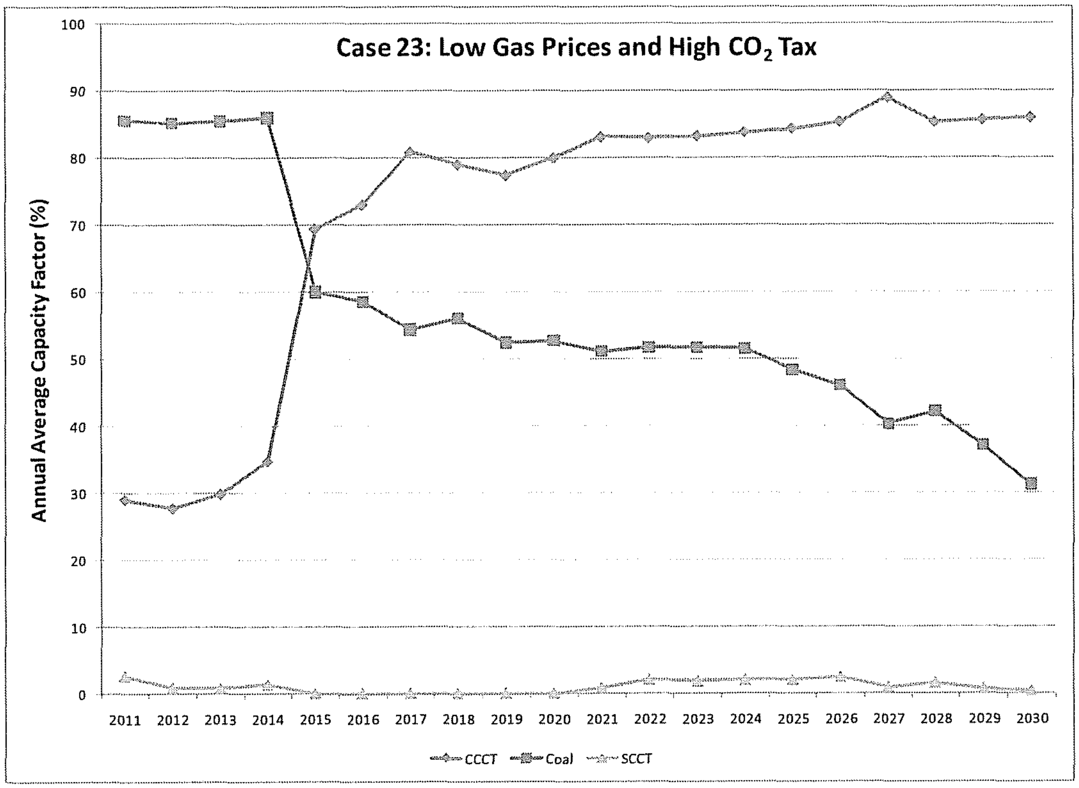
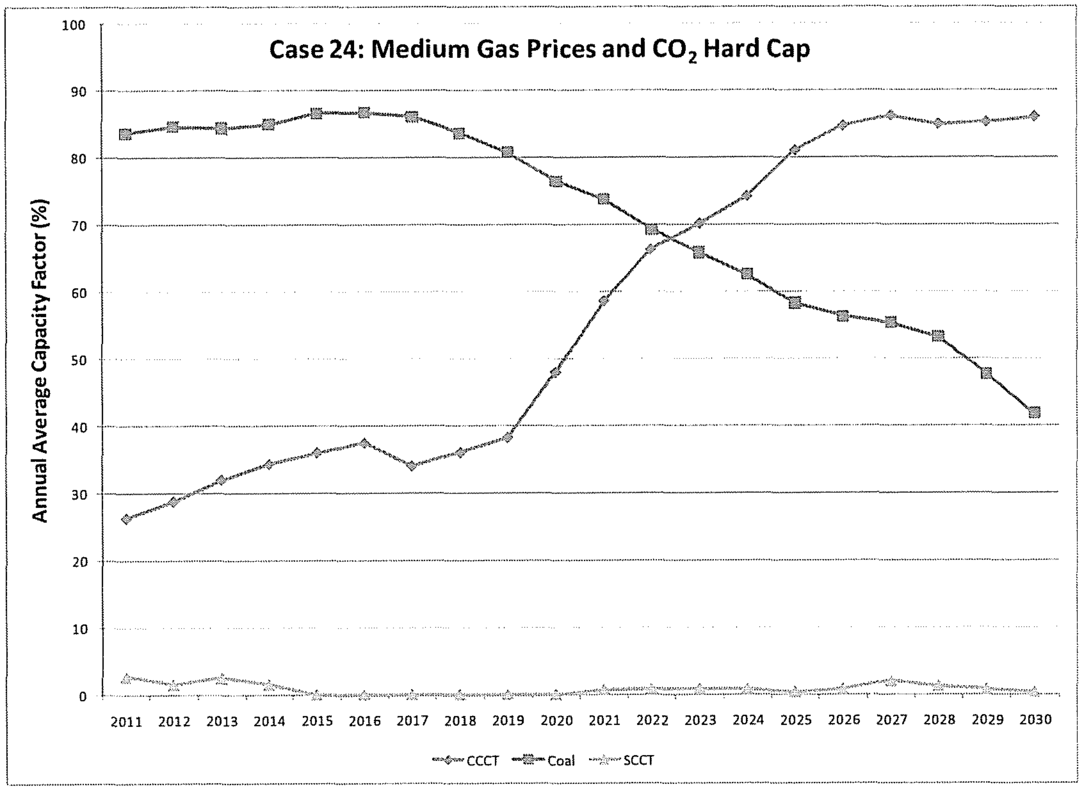


Figure 8.21 – Gas and Coal Plant Utilization Trends, Case 24



As expected, with no CO_2 tax in place, annual coal plant utilization continues at a relatively steady 80 to 90 percent, except for a temporary dip in 2026 and 2027 when an influx of Alaskan gas is forecast to cause a temporary drop in gas prices. The largest impact on coal plant utilization comes from the combination of low gas price and high CO_2 tax scenario assumptions, which reduces the fleet-wide utilization rate to 35 percent by 2030.

Key conclusions from this study, notwithstanding uncertainties in environmental compliance costs, include the following:

- The Company's coal fleet remains economically viable under currently expected natural gas prices and given a CO_2 cost that is line with recent federal carbon emissions control proposals.
- Sustained low natural gas prices or imposition of CO_2 costs, considered individually, have a moderate impact on the continued operation of the coal fleet.
- Assuming sustained low natural gas prices are combined with sustained high carbon costs or a hard cap is put in place, the utilization of the coal fleet is significantly reduced. However, CCCT replacements are cost-effective for a limited number of coal units, and the replacements do not occur until the late-2020s.
- A CO_2 cost of around $40/ton and sustained gas prices in the $7 - $9/MMBtu range (both in nominal dollars) are needed to begin to make coal plant replacements cost-effective prior to 2030.

Appendix E in Volume 2 reports stochastic analysis results for these portfolios. See Tables E.7, E.8, and E.12 through E.14.

Out-year Optimization Impact Analysis
In its 2008 IRP acknowledgment order, the Oregon Commission directed PacifiCorp to "work with parties to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan, and for which the Company can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan."[71]

For this investigation, the Company applied a two-stage System Optimizer capacity expansion approach. The first stage is a conventional 20-year simulation of a test portfolio ("Full Optimization"). Case 9 was selected because it was defined with the "Low to Very High" CO_2 tax scenario, marked by an acceleration of the CO_2 tax beginning in 2021. The model has perfect foresight, and thus optimizes with knowledge of the full CO_2 price trajectory. The second stage ("Partial Optimization") involved developing a portfolio with two separate System Optimizer runs. The first run was conducted for a 12-year span, 2011-2022, rather than just 10 years to account for optimization period end effects. The second run involved fixing the resources from the first run for 2011 through 2020[72], but allowing System Optimizer to fully optimize for 2021 through 2030. This two-stage approach isolates the impact of giving the model perfect foresight for out-year CO_2 tax values and other case scenario input values.

Table 8.19 shows the resource capacity differences on an annual basis for the Full Optimization and Partial Optimization portfolios.

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[71] Public Utility Commission of Oregon, Order, Modified Plan Acknowledged with an Exception, Docket No. LC 47, p. 27.
[72] An exception for energy efficiency was made due to set-up complications in fixing these resources. The model was allowed to optimize them for the full 20 years.

The major resource impacts of moving to the Partial Optimization approach for this case are as follows:

- The second CCCT was deferred by one year, from 2015 to 2016.
- The resulting CCCT deferral capacity shortage in 2015 was made up by higher front office transactions, the addition of utility-scale biomass (50 MW), and an acceleration of Class 2 DSM.
- Solar hot water resources, both east and west side, were eliminated, along with 82 MW of wind added in 2024 through 2028.

As expected, the Partial Optimization portfolio had a higher PVRR relative to the fully optimized 20-year run, an increase of $247 million.

The main conclusion from this test case is that foreknowledge of out-year CO_2 tax values and other input assumptions affected the model's resource selection and timing in the Action Plan time horizon. What is the implication for PacifiCorp's portfolio evaluation approach? PacifiCorp does not use System Optimizer economic results to determine the preferred portfolio. Rather, it is used to generate alternative portfolios for detailed stochastic production simulation. To the extent that a two-stage modeling approach results in significantly different portfolios from conventional simulations, then it may have some value from the perspective of creating a more diverse portfolio set. However, the added complexity of setting up the model and running simulations in this fashion for the entire portfolio development process is not practical.

Although not part of the Oregon Commission's IRP analysis requirement, the Company has addressed the same out-year portfolio simulation concerns with regard to the stochastic simulations used for preferred portfolio selection. As noted in Chapter 7, the Company eliminated the long-term stochastic volatility parameters from the Monte Carlo simulations. That action was found to decrease out-year impacts on overall portfolio costs.

Table 8.19 – Resource Differences, Full Optimization Portfolio less Partial Optimization Portfolio, Case 9 Assumptions

		Capacity (MW)																			
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
East																					
	CCCT F 2x1 (Utah South)	-	-	-	-	597	(597)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	13	49	21	(0.3)	(0.3)	-	-
	CHP - Reciprocating Engine	-	-	-	-	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	(3.2)	-	-	4.9	-	-	5.4	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2 Total	-	-	-	(4.0)	(17.4)	3.6	4.2	3.8	5.2	5.5	-	-	-	-	-	-	-	-	-	-
	Micro Solar - Water Heating	-	-	-	-	-	3	3	3	3	3	-	-	-	-	0.3	-	-	-	-	-
	FOT Mead Q3 HLH	-	(0)	-	-	(99)	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FOT Utah Q3 HLH	-	-	-	16	(200)	-	53	48	-	21	-	-	-	-	-	-	-	-	-	-
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	(1)	28	(29)	(6)	(1)	(1)	(3)	18	(0)	(5)
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	9	28	29	(8)	(74)	12	3	-
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	10	9	13	46	(156)	22	7	47
West																					
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35)	-	-	-	-
	CHP - Reciprocating Engine	-	-	-	-	(0.3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	41.2	(8.5)	(1.5)	-	6.4	-	-	3.6	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2 Total	(1.8)	-	(0.3)	(0.5)	(0.5)	1.0	0.6	0.8	0.6	0.6	-	-	-	-	-	-	-	-	-	-
	Micro Solar - Water Heating	-	-	-	-	-	2	2	2	2	2	-	0.3	-	-	-	-	-	-	-	-
	FOT MidColumbia Q3 HLH	-	-	-	-	(102)	-	-	-	37	-	32	4	-	-	-	119	-	-	-	-
	FOT MidColumbia Q3 HLH, 10% premium	-	(0.1)	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FOT West Main Q3 HLH	-	-	-	-	(50)	48	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	(1)	-	-	-	-
	Growth Resource Oregon and California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	316	-	-	-
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	41	-	(10)	(94)	(21)	10	53	21

Alternative Load Forecast Cases

PacifiCorp ran System Optimizer for three alternative load growth scenarios: low economic growth (Case 25), high economic growth (Case 26), and 1-in-10 year extreme summer/winter peaks (Case 27). The resulting System Optimizer portfolios for Case 25 and Case 26 were compared with the Case 7 portfolio, which is based on same medium CO_2 and gas price scenarios. The period examined was for years 2011 through 2020. (Resource tables showing the full 20-year view are included in Appendix D). Table 8.20 summarizes the year-by-year resource capacity differences between Cases 7, 25, and 26. With lower economic growth, the model eliminates gas capacity, and increases DSM to facilitate the gas capacity reductions and deferrals. With higher economic growth, gas resources acquisitions are accelerated, the amount of DSM is increased, and acquisition of front office transactions is shifted from the west to the east with a net gain in quantity.

Table 8.20 – Resource Differences, Case 7 vs. Low and High Economic Growth Portfolios

Case 7 Less Case 25 (Low Econ. Load Growth)

		Capacity (MW)										10-Yr
	Resource	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Totals**
East												
	CCCT F 2x1	-	-	-	(625.0)	28.0	-	-	597.0	-	-	-
	CCCT H 2x1	-	-	-	-	-	-	-	-	(475.0)	-	(475)
	CHP - Reciprocating Engine	-	-	-	0.8	-	0.8	0.8	-	-	-	2
	DSM, Class 1	-	(3.5)	-	6.7	-	7.0	(7.8)	-	-	-	2
	DSM, Class 2	1.9	8.8	3.0	22.6	4.1	4.4	10.3	3.4	4.8	10.1	73
	FOT Mead Q3 HLH	-	-	-	-	4.2	71.0	-	-	-	-	75
	FOT Utah Q3 HLH	-	(5.2)	(0.9)	178.2	-	67.5	143.3	(200.0)	-	7.4	N/A
West												
	CHP - Reciprocating Engine	-	-	-	0.3	-	0.3	0.3	-	-	-	1
	DSM, Class 1	-	-	(6.8)	16.7	-	-	(10.0)	-	-	-	-
	DSM, Class 2	0.5	0.5	0.6	0.6	0.7	0.7	0.6	0.6	0.8	0.8	6
	Micro Solar - Water Heating	-	-	-	-	-	-	-	-	0.5	0.5	1
	FOT MidColumbia Q3 HLH	(1.5)	-	-	-	96.8	-	-	(142.0)	20.5	-	N/A
	FOT MidColumbia Q3 HLH, 10% Premium	-	(0.4)	(0.6)	-	-	-	-	-	-	-	N/A
	FOT Oregon/California Q3 HLH	-	-	-	-	50.0	-	-	(50.0)	-	-	N/A

Case 7 Less Case 26 (High Econ. Load Growth)

		Capacity (MW)										10-Yr
	Resource	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Totals**
East												
	CCCT F 2x1	-	-	-	-	-	-	597.0	-	-	-	597.0
	CCCT H 2x1	-	-	-	-	-	-	-	-	(475.0)	-	(475.0)
	Aero SCCT	-	-	-	-	-	-	-	-	-	118.0	118.0
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	45.0	(45.0)	-
	CHP - Reciprocating Engine	-	-	-	0.8	-	-	-	-	-	0.8	1.5
	DSM, Class 1	-	-	-	3.2	-	-	(7.8)	-	7.0	-	2.4
	DSM, Class 2	-	0.0	-	11.6	2.4	3.1	3.2	4.7	19.8	20.1	64.9
	FOT Mead Q3 HLH	-	-	-	-	45.1	71.0	-	-	-	-	N/A
	FOT Utah Q3 HLH	-	-	-	178.2	-	119.2	(56.7)	(200.0)	7.6	7.4	N/A
West												
	Utility Biomass	-	-	-	-	50.0	-	-	-	-	-	50.0
	CHP - Reciprocating Engine	-	-	-	0.3	-	-	-	-	-	-	0.3
	DSM, Class 1	-	-	-	10.0	-	-	(10.0)	-	-	-	-
	DSM, Class 2	0.2	0.3	0.6	0.6	0.4	0.6	0.6	0.6	0.8	0.8	5.5
	Micro Solar - Water Heating	-	-	-	-	-	-	-	-	0.5	0.5	1.0
	FOT MidColumbia Q3 HLH	(0.1)	-	-	-	96.8	-	(191.9)	(40.2)	24.1	-	N/A
	FOT MidColumbia Q3 HLH, 10% Premium	-	(0.2)	(0.4)	-	-	-	-	-	-	-	N/A
	FOT Oregon/California Q3 HLH	-	-	-	-	50.0	-	(50.0)	(50.0)	50.0	-	N/A

For the high peak demand portfolio (Case 27), the comparison was made with the high economic growth portfolio (Case 26). Table 8.21 summarizes the year-by-year resource capacity differences between these two portfolios for 2011-2020. As indicated in the table, additional simple-cycle combustion turbine capacity is needed under the high peak demand scenario, and the need is accelerated to 2014 from 2020. Small quantities of additional Class 2 DSM in the east are also chosen above what is selected under the high economic growth scenario.

Table 8.21 – Resource Differences, High Peak Demand vs. High Economic Growth Portfolios

Case 27 (High Peak Demand) less Case 26 (High Econ. Growth)

		Capacity (MW)										10-Yr
	Resource	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Totals**
East												
	CCCT F 2x1	-	-	-	-	-	-	(597.0)	597.0	-	-	-
	SCCT Aero	-	-	-	236.0	-	-	-	-	-	(118.0)	118.0
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	(45.0)	45.0	-
	CHP - Reciprocating Engine	-	-	-	(0.8)	-	0.8	0.8	0.8	0.8	-	2.3
	DSM, Class 1	-	(3.5)	-	-	-	1.6	-	-	(7.0)	8.8	-
	DSM, Class 2	-	4.2	-	(8.2)	1.7	1.3	1.2	6.6	-	-	6.9
	FOT Mead Q3 HLH	-	-	-	-	(45.1)	-	-	-	-	-	N/A
	FOT Utah Q3 HLH	-	-	-	(23.2)	-	(68.8)	200.0	-	(7.6)	-	N/A
West												
	CHP - Reciprocating Engine	-	-	-	(0.3)	-	0.3	0.3	0.3	0.3	0.3	1.4
	DSM, Class 1	-	-	-	(3.6)	-	1.3	-	-	-	2.3	-
	DSM, Class 2	(0.2)	-	(0.3)	(0.2)	0.3	0.1	-	-	-	0.1	(0.3)
	FOT MidColumbia Q3 HLH	0.1	-	-	-	-	-	191.9	(93.4)	-	-	N/A
	FOT MidColumbia Q3 HLH , 10% price premi	-	0.1	0.2	-	-	-	-	-	-	-	N/A
	FOT Oregon/California Q3 HLH	-	-	-	-	(28.2)	-	50.0	-	(49.5)	-	N/A
	Annual Additions, Long Term Resources	(0)	1	(0)	223	2	5	(595)	605	(51)	(61)	
	Annual Additions, Short Term Resources	0	0	0	(23)	(73)	(69)	442	(93)	(57)	-	
	Total Annual Additions	(0)	1	(0)	200	(71)	(63)	(153)	511	(108)	(61)	

Appendix E in Volume 2 reports stochastic analysis results for the low and high economic growth portfolios. Stochastic analysis was not conducted for the high peak demand portfolio because resource differences are not significantly different from the high economic growth portfolio. See Tables E.6, E.7, and E16 through E.18.

Renewable Resource Cases

This section presents System Optimizer simulation results for four sensitivity cases that test alternative renewable energy policy assumptions and resource costs. Case 28 determines the resource and cost impact of excluding state RPS requirements as a portfolio development constraint. Case 29 tests an alternate wind integration cost of $5.38/MWh, versus the $9.70/MWh value reported in PacifiCorp's 2010 wind integration study (Appendix I). Cases 30 and 30a determine if System Optimizer selects Utah solar PV resources assuming a resource cost based on alternative levels for a utility incentive program; $1,744/kW and $2,326/kW, respectively. PacifiCorp also determined the impact of an aggressive federal RPS requirement (Waxman-Markey targets, 20 percent by 2020) on the preferred portfolio.

Utah Utility Cost Buy-down for Solar PV Resources

For Case 30—$1,744/kW utility program cost—System Optimizer selected the maximum annual amount per year (1.2 MW) for 2011 through 2028, amounting to 22 MW. The deterministic PVRR for this portfolio was $41.04 billion.

For Case 30a—$2,326/kW utility program cost—System Optimizer selected the maximum annual amount per year (1.2 MW) for 2011 through 2020, amounting to 12 MW. The deterministic PVRR for this portfolio was $3 million higher than the PVRR for the Case 30 portfolio.

PacifiCorp conducted accompanying System Optimizer runs to determine the portfolio cost impact on a Total Resource Cost (TRC) basis for comparability to other resource portfolios. (As noted in Chapter 7, comparing portfolios with generation resources specified with a different cost basis and exhibiting such a wide gap between utility cost and total resource cost does not meet the state IRP Standards and Guidelines provision to evaluate resources "on a consistent and comparable basis".) For these model runs, PacifiCorp fixed the Utah solar PV amounts selected in the original runs, but used the original resource costs. Table 8.22 shows the PVRR comparison between the buy-down utility-cost-based program cost portfolios and portfolios that included the solar PV resources on a TRC basis.

Table 8.22 – Solar PV Resource Comparison, Buy-Down Utility Cost versus Total Resource Cost PVRR

Sensitivity Case	PVRR, Program Cost Basis, Utah Solar PV Resources (Million $)	PVRR, TRC Basis, Utah Solar PV Resources (Million $)	PVRR Difference, TRC less Program Cost (Million $)
30	41,038	41,064	26.7
30a	41,041	41,058	17.1

Renewable Portfolio Standard Impact

For Case 28, PacifiCorp removed the system renewable portfolio standard constraints originally applied to Case 7 (medium gas prices/medium CO_2 tax). This sensitivity determines the cost-effective amount of renewable capacity added by System Optimizer at these gas and CO_2 price levels. With the RPS constraints removed, the model added 150 MW of geothermal capacity but no wind. Table 8.23 compares the year by year resource capacity differences between the "no RPS" portfolio and the Case 7 portfolio. With the RPS included, the model selected 137 MW of wind and 70 MW of geothermal (35 MW in the east and 35 MW in the west). Portfolio PVRR increased by $223 million to comply with the RPS constraints.

Alternate Wind Integration Cost

For Case 29, PacifiCorp assigned the alternate wind integration cost of $5.38/MWh to wind resources. The resulting portfolio was compared to the Case 7 portfolio, which serves as the base. As shown in Table 8.23, which shows the annual and total resource differences between the two portfolios, the lower wind integration cost increased the amount of wind selected by 81 MW. The higher capacity was accompanied by a reduction in DSM, less geothermal capacity in west, and greater reliance on out-year growth resources in the west.

Table 8.23 – Resource Differences, Renewable Portfolio Standard and Alternate Wind Integration Cost Impact

Case 7 Less Case 28 (No RPS Requirements)

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals 2/ 10-year	20-year
East																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	12	49	21	8	9	4	34	-	137
	DSM, Class 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9	(4.9)	-	-	-
	DSM, Class 2	-	0.0	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	(2.5)	0	(2)
	Micro Solar - Hot Water Heating	-	-	-	-	-	-	-	-	-	-	3	3	3	3	2	-	-	-	-	-	-	13
	FOT Mead Q3	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT Utah Q3	-	-	-	0	-	-	(4)	(4)	-	-	-	-	-	-	-	-	-	-	-	-	(7)	(7)
	Growth Resource Goshen 1/	-	-	-	-	-	-	-	-	-	-	(0)	31	96	48	(38)	(58)	(0)	(49)	(30)	(0)	-	0
	Growth Resource Utah North 1/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28	-	(2)	28	(53)	N/A	(0)
	Growth Resource Wyoming 1/	-	-	-	-	-	-	-	-	-	-	-	-	2	53	7	(37)	-	13	(26)	(12)	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1	-	-	-	-	-	-	3.6	-	-	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2	(0.1)	-	-	(0.1)	(0.3)	0.2	-	-	-	-	-	(0.3)	-	-	-	-	-	(0.2)	-	(0.2)	(0)	(1)
	Micro Solar - Hot Water Heating	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	-	-	-	-	-	-	6
	FOT MidColumbia Q3 HLH	-	-	-	-	0	-	-	-	(4)	-	314	132	23	5	-	-	-	-	-	-	(0)	23
	FOT MidColumbia Q3 HLH, 10% price premium	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Walla Walla 1/	-	-	-	-	-	-	-	-	-	-	-	(21)	-	-	44	49	22	5	19	44	N/A	16
	Growth Resource Oregon/California 1/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	-	-	-	N/A	(7)
	Growth Resource Yakima 1/	-	-	-	-	-	-	-	-	-	-	(315)	(145)	(126)	(111)	(82)	(51)	(24)	(41)	(59)	(46)	N/A	(100)

Case 29 (Alternate Wind Integration Cost) less Case 7

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals 2/ 10-year	20-year
East																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	(35.0)	-	-	-	-	-	35.0	-
	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	(12.1)	111.1	(17.8)	-	-	-	-	-	81.3
	DSM, Class 1	-	-	-	-	-	-	-	-	-	(5.4)	-	-	-	-	-	-	-	(4.9)	4.9	-	(5.4)	(5.4)
	DSM, Class 2	-	(0.0)	-	(0.6)	-	(3.1)	(3.2)	(3.4)	(4.8)	(5.5)	-	-	-	-	-	-	-	-	-	-	(20.7)	(20.7)
	Micro Solar - Hot Water Heating	-	-	-	-	-	-	-	-	-	-	(2.6)	(2.6)	(2.6)	(2.6)	(2.4)	-	-	-	-	-	-	(12.9)
	FOT Mead Q3 HLH	-	-	-	-	-	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	3.1
	FOT Utah Q3 HLH	-	-	-	0.6	-	-	7.1	9.8	-	(7.2)	-	-	-	-	-	-	-	-	-	-	10.3	10.3
	Growth Resource Goshen 1/	-	-	-	-	-	-	-	-	-	-	0.2	(30.9)	(115.7)	(63.9)	64.1	61.9	0.4	45.1	38.4	0.4	-	(0.0)
	Growth Resource Utah North 1/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(18.0)	-	(16.4)	(8.6)	43.0	N/A	0.0
	Growth Resource Wyoming 1/	-	-	-	-	-	-	-	-	-	-	-	-	(2.2)	(52.8)	(6.6)	12.7	-	10.3	25.6	13.1	N/A	0.0
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35.0)	-	-	-	-	-	-	(35.0)
	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1	-	-	-	-	-	-	(1.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.6)	(1.6)
	DSM, Class 2	0.1	-	(0.4)	-	(0.1)	(0.6)	(0.5)	(0.6)	(0.8)	(0.8)	-	0.3	-	-	-	-	-	0.2	-	-	(3.7)	(3.2)
	Micro Solar - Hot Water Heating	-	-	-	-	-	-	-	-	(0.8)	(0.8)	(0.3)	(1.3)	(1.3)	(1.3)	(1.0)	-	-	-	-	-	(1.7)	(6.8)
	FOT MidColumbia Q3 HLH	-	-	-	-	0.6	-	-	-	14.0	-	(196.6)	(119.2)	(11.2)	-	-	-	-	-	-	-	1.5	(15.6)
	FOT MidColumbia Q3 HLH, 10% price premium	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0
	Growth Resource Walla Walla 1/	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	(107.6)	(102.5)	(37.5)	(5.1)	(83.2)	(38.1)	N/A	(37.2)
	Growth Resource Oregon/California 1/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	56.1	-	-	-	N/A	5.6
	Growth Resource Yakima 1/	-	-	-	-	-	-	-	-	-	-	190.4	143.6	125.9	114.9	111.5	107.4	42.4	32.2	89.0	42.8	N/A	100.0

1/ Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

2/ Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Demand-side Management Cases

This section presents System Optimizer simulation results for three sensitivity cases that test alternative DSM resources (Class 3 DSM and distribution energy efficiency) and use of technical DSM potential in lieu of achievable potential for preferred portfolio resource selection.

Demand Response Program (Class 3 DSM) Impact

Case 31 entailed including Class 3 DSM rate products as resource options using the medium natural gas and CO_2 tax assumptions defined for Case 7. As noted in Chapter 7, the dispatchable irrigation load control programs were assumed to be substituted by a mandatory Time of Use (TOU) rate schedule with rates set sufficiently high to induce the desired load shifting behavior. This substitution occurs in 2015, when a TOU rate structure is assumed to be instituted. The resource potentials account for interaction effects between Class 1 and Class 3 resources. Table 8.24 shows the resource differences between the portfolio with Class 3 DSM selected and the reference portfolio derived from Case 7 assumptions.

A total of 262 MW of Class 3 DSM was selected in the east and 131 MW selected in the west. The net gain in load control resources is 122 MW, which accounts for reduced Class 1 DSM capacity (70 MW) and the displacement of the dispatchable irrigation load control program (201 MW). This additional DSM capacity is sufficient to defer the second and third CCCT resources by one year. The portfolio PVRR decreased by about $236 million due to the relatively low cost of administering 3 DSM programs.

Technical DSM Potential Supply Curve versus High Achievable Potential Supply Curve

For Case 32, PacifiCorp substituted DSM supply curves based on a high achievable potential adjustment (85 percent) with a version for which the achievable potential adjustment is removed. (As noted in Chapter 6, the achievable potential reflects the resource quantity available after accounting for market and adoption barriers. Comparing the resulting portfolio with the base (Case 7 portfolio) indicates the amount of cost-effective technical potential selected by System Optimizer. As shown in Table 8.25, which shows the year by year resource comparison of the two portfolios, removing the achievable potential adjustment increased the cumulative amount of energy efficiency (Class 2 DSM) by 418 MW. The model used this incremental DSM, along with the selection of smaller resources and increased front office transactions in certain years, to defer the 2015 and 2019 CCCT resources by one year. Given that the 85-percent achievable potential adjustment is aspirational, PacifiCorp considers additional DSM potential beyond the 85-percent adjustment to be effectively a non-firm resource, and would have serious concerns about using it as the basis for program target setting.

Washington Distribution Energy Efficiency Resource

For this sensitivity case (Case 33), PacifiCorp included a proxy resource option in System Optimizer representing Washington distribution energy efficiency resources for the Yakima/Sunnyside and Walla Walla areas. The model selected the full amount of the Walla Walla resource in 2013 (0.191 MW), and the full amount of the Yakima/Sunnyside resource in 2016 (0.403 MW).

Table 8.24 – Resource Differences, Class 3 DSM Portfolio (Case 31) less Case 7 Portfolio

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals 1/ 10-year	20-year
East																						
CCCT F 2x1 (Utah North)	-	-	-	-	(597)	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT H (Utah South)	-	-	-	-	-	-	-	-	(475)	475	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal, Blundell 3	-	-	-	-	-	-	-	-	45	(45)	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	(35)	-	-	-	35	-	-	-	-	-	-	(35)	-
DSM, Class 1, Idaho, DLC-Irrigation	-	-	-	(19.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4.9)	-	(20)	(25)
DSM, Class 1, Utah, C&I-Thermal Energy Storage	-	(3.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)
DSM, Class 1, Utah, Curtailment	-	-	-	-	-	-	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	(5)	(5)
DSM, Class 1, Utah, DLC-Residential	-	(3.2)	-	-	-	-	(3.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	(6)	(6)
DSM, Class 3, Idaho, C&I-Critical Peak Pricing	-	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 3, Idaho, TOU-Irrigation	-	-	-	141.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	142	142
DSM, Class 3, Utah, C&I-Critical Peak Pricing	-	-	-	16.9	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 3, Utah, Demand Buyback	-	6.2	-	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	9	9
DSM, Class 3, Utah, TOU-Irrigation	-	-	-	35.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
DSM, Class 3, Utah, C&I-Real Time Pricing	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 3, Wyoming, C&I-Critical Peak Pricing	-	-	-	10.5	-	-	-	-	-	10.1	-	-	-	-	-	-	-	-	-	-	21	21
DSM, Class 3, Wyoming, Demand Buyback	-	4.8	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	10	10
DSM, Class 3, Wyoming, TOU-Irrigation	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 3, Wyoming, C&I-Real Time Pricing	-	-	-	2.7	-	-	-	-	-	2.7	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1 & 3 Total	-	4.3	-	201.3	-	-	(7.8)	-	-	29.6	-	-	-	-	-	-	-	-	(4.9)	-	227	222
DSM, Class 2 Total	12.2	10.5	5.2	-	(0.7)	(0.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
Micro Solar - Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	-	-	-	-	-	(0)
FOT Mead Q3 HLH	-	-	-	(60)	99	(28)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
FOT Utah Q3 HLH	-	(22)	-	(22)	151	-	(57)	(112)	194	(111)	-	-	-	-	-	-	-	-	-	-	22	22
Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	3	3	(27)	(51)	(60)	76	(28)	25	59	-	0
Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	(25)	20	(39)	N/A	0
Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)	190	(32)	(36)	(99)	N/A	0
West																						
DSM, Class 1, California, DLC-Irrigation	-	-	(5.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(5)	(5)
DSM, Class 1, Oregon, Curtailment	-	-	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)
DSM, Class 1, Oregon, DLC-Irrigation	-	-	(13.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(13)	(13)
DSM, Class 1, Oregon, DLC-Residential	-	-	(4.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)	(4)
DSM, Class 1, Washington, DLC-Irrigation	-	-	(2.1)	-	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	(9)	(9)
DSM, Class 1, Washington, DLC-Residential	-	-	(0.1)	-	-	-	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)	(4)
DSM, Class 3, Oregon, TOU-Irrigation	-	-	-	72.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	72
DSM, Class 3, California, TOU-Irrigation	-	-	-	25.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 3, Washington, TOU-Irrigation	-	-	-	27.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28	28
DSM, Class 3, Oregon, C&I-Critical Peak Pricing	-	-	-	5.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 & 3 Total	-	-	(26.5)	131.5	-	-	(10.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	95	95
DSM, Class 2 Total	-	0.1	0.2	(0.4)	(0.4)	(0.4)	(0.1)	(0.2)	-	-	-	(0.3)	-	-	-	-	-	(0.2)	-	-	(1)	(2)
Micro Solar - Water Heating	-	-	-	-	-	-	-	-	1	(0)	-	-	-	(0)	-	-	-	-	-	-	0	0
FOT MidColumbia Q3	(9)	-	-	-	97	(52)	(6)	-	24	-	106	39	12	-	-	-	-	-	-	-	5	11
FOT MidColumbia Q3 HLH, 10% price premium	-	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
FOT Oregon/Washington Q3 HLH	-	-	-	(50)	50	(50)	(50)	-	50	-	-	-	-	-	-	-	-	-	-	-	(5)	(3)
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	(12)	-	-	(30)	52	(44)	-	(32)	7	N/A	(6)
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(412)	-	-	-	N/A	(41)
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	(217)	(140)	(126)	(114)	(61)	(110)	4	(57)	(114)	(65)	N/A	(100)
Annual Additions, Long Term Resources	12	15	(21)	332	(598)	596	(18)	(0)	(429)	424	-	(0)	(0)	35	-	-	-	(0)	(5)	-		
Annual Additions, Short Term Resources	(9)	(22)	0	(132)	397	(130)	(112)	(112)	268	(111)	(111)	(111)	(111)	(142)	(142)	(142)	(142)	(142)	(137)	(137)		
Total Annual Additions	3	(7)	(21)	201	(201)	466	(130)	(112)	(161)	313	(111)	(111)	(111)	(107)	(142)	(142)	(142)	(142)	(142)	(137)		

1/ Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive. FOT are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table 8.25 – Resource Differences, Technical DSM Potential vs. Economic DSM Potential

Case 32 (Technical DSM Potential) less Case 7 (High Achievable Potential)

		Capacity (MW)																				Resource Totals 2/	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	-	(597.0)	597.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CCCT H 2x1	-	-	-	-	-	-	-	-	(475.0)	475.0	-	-	-	-	-	-	-	-	-	-	-	-
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	45.0	(45.0)	-	-	-	-	-	-	-	-	-	-	-	-
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	(35.0)	-	-	-	-	35.0	-	-	-	-	-	(35.0)	-
	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(8.2)	(9.1)	(3.6)	(26.8)	-	(47.6)
	CHP - Reciprocating Engine	(0.8)	(0.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.5)	(1.5)
	DSM, Class 1	-	(3.5)	-	0.8	2.4	-	(7.8)	-	-	-	-	-	-	-	-	-	-	-	(4.9)	4.9	(8.1)	(8.1)
	DSM, Class 2, Idaho	0.3	0.3	0.4	0.5	0.6	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.1	1.1	1.2	1.1	1.2	1.1	1.1	1.0	6.1	16.7
	DSM, Class 2, Utah	8.4	4.2	(4.9)	11.0	11.8	13.1	13.6	14.0	14.7	15.9	18.1	19.6	18.3	18.5	18.0	20.5	19.0	20.1	19.2	20.0	101.8	293.1
	DSM, Class 2, Wyoming	0.6	1.2	1.2	1.6	1.5	0.8	.1.9	2.2	2.1	2.3	2.6	2.7	3.2	4.0	4.2	5.5	5.9	6.8	8.6	9.1	15.3	67.9
	DSM, Class 2 Total	9.3	5.7	(3.3)	13.1	13.9	14.6	16.3	17.0	17.6	19.0	21.5	23.2	22.6	23.6	23.4	27.1	26.1	28.0	29.0	30.1	123.2	377.7
	Micro Solar - Hot Water Heating	-	-	-	-	-	-	-	-	-	-	(2.4)	(2.4)	(0.0)	-	-	-	-	-	-	-	-	(4.8)
	FOT Mead Q3 HLH	-	-	-	-	99.1	(28.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	71.0	71.0
	FOT Utah Q3 HLH	-	(6.5)	-	(21.8)	200.0	-	(56.7)	(108.7)	181.3	(111.4)	-	-	-	-	-	-	-	-	-	-	76.3	76.3
	Growth Resource Goshen 1/	-	-	-	-	-	-	-	-	-	-	-	13.0	36.1	(14.9)	(92.8)	(15.2)	155.1	(99.5)	(35.8)	54.1	-	0.0
	Growth Resource Utah North 1/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(134.1)	(133.0)	(153.0)	N/A	(42.0)
	Growth Resource Wyoming 1/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(53.4)	206.3	(49.5)	(57.6)	(45.8)	N/A	0.0
West																							
	Utility Biomass	-	-	-	-	50.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50.0	50.0
	CHP - Reciprocating Engine	(0.3)	(0.3)	(0.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.9)	(0.9)
	DSM, Class 1	-	-	-	6.4	0.9	-	(10.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	(2.7)	(2.7)
	DSM, Class 2, California	0.2	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.3	0.4	0.3	0.3	0.3	2.1	5.5
	DSM, Class 2, Washington	1.5	1.5	2.0	1.7	1.6	1.5	1.4	1.4	1.7	1.7	1.9	2.1	2.0	2.1	2.2	1.8	1.5	1.6	1.6	1.7	16.0	34.6
	DSM, Class 2 Total	1.7	1.6	2.1	1.9	1.8	1.8	1.7	1.7	1.9	2.0	2.2	2.4	2.4	2.5	2.6	2.1	1.9	2.0	2.0	2.0	18.1	40.1
	Micro Solar - Hot Water Heating	-	-	-	-	-	-	-	-	0.5	(0.3)	-	-	(1.0)	(1.0)	-	-	-	-	-	-	0.2	(1.7)
	FOT MidColumbia Q3 HLH	(7.1)	-	-	-	96.8	(17.9)	-	-	24.1	-	(95.6)	(291.7)	(387.7)	(378.7)	-	-	-	-	-	-	9.6	(52.9)
	FOT MidColumbia Q3 HLH, 10% price premium	-	(1.6)	(2.3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.4)	(0.2)
	FOT Oregon/California Q3 HLH	-	-	-	-	50.0	(50.0)	(36.5)	-	50.0	-	-	-	-	-	-	-	-	-	-	-	1.4	0.7
	Growth Resource Walla Walla 1/	-	-	-	-	-	-	-	-	-	-	-	(12.0)	-	-	(55.9)	(51.8)	(167.3)	-	(31.6)	(164.6)	N/A	(48.3)
	Growth Resource Oregon/California 1/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(412.0)	-	-	-	N/A	(41.2)
	Growth Resource Yakima 1/	-	-	-	-	-	-	-	-	-	-	(34.6)	140.2	180.8	201.6	(95.6)	(148.2)	(73.7)	(33.2)	(78.7)	(58.6)	N/A	(0.0)
	Annual Additions, Long Term Resources	10	3	(1)	22	(528)	613	0	19	(410)	416	21	23	24	25	61	29	20	21	22	10		
	Annual Additions, Short Term Resources	(7)	(8)	(2)	(22)	446	(96)	(93)	(109)	255	(111)	(130)	(151)	(171)	(192)	(244)	(269)	(292)	(316)	(337)	(368)		
	Total Annual Additions	3	(5)	(4)	0	(82)	517	(93)	(90)	(155)	304	(109)	(127)	(147)	(167)	(183)	(239)	(272)	(295)	(314)	(358)		

1/ Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.
2/ Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Cost of Energy Not Served (ENS) Sensitivity Analysis

In its 2008 IRP acknowledgment order, the Utah Commission directed the Company to "perform a sensitivity case in its next IRP or IRP update wherein the ENS cost is flat and based on the Federal Energy Regulatory Commission price cap."[73]

Using the Case 7 portfolio, PacifiCorp applied the two ENS price structures to the quantity of ENS reported from the Planning and Risk simulation for the medium CO_2 tax scenario: the current FERC price cap of $750/MWh, and the tiered pricing approach adopted by the Company. The tiered approach assigns a price of $400/MWh for the first 50 GWh, $200/MWh for ENS in the range of 51 to 150 GWh, and $100/MWh for ENS above 150 GWh.

Substituting the PacifiCorp's ENS price structure with the $750/MWh FERC price cap raises the ENS cost by $158 million for the 20-year simulation. It should be noted that the ENS price entered into the PaR model does not affect the model's unit commitment and dispatch solution. Energy Not Served is an outcome of the inability to meet load, and is not affected by the assigned ENS price. In other words, the ENS price is simply used to value the unmet load for reporting purposes.

PacifiCorp's updated ENS pricing approach has been to assign a price representative of what emergency power would be under adverse market circumstances for ENS experienced in the short term, and representative of the acquisition of peaking resources for ENS experienced in the long term (in the later years of the simulation where ENS becomes significant). The upshot is that the choice of an ENS value is fundamentally a subjective decision. The Company's view is that it is inappropriate to assign too high an ENS price given that portfolio costs generated farther out in the Monte Carlo simulation become increasingly influenced by stochastic outlier events. Assigning a high ENS price increases the influence of such out-year outlier events on overall portfolio costs.

[73] Public Service Commission of Utah, Report and Order, PacifiCorp 2008 Integrated Resource Plan, Docket No. 09-2035-01, p. 24.

CHAPTER 9 – ACTION PLAN

Chapter Highlights

- *The 2011 IRP action plan identifies steps to be taken during the next two to four years to implement the IRP. The preferred portfolio reflects a snapshot view of the future that accounts for a wide range of uncertainties, and is not intended as a procurement commitment.*
- *The Company plans to acquire up to 800 MW of wind resources by 2020 guided by consideration of regulatory compliance risks and public policy interest in clean energy resources.*
- *The Company will investigate, and pursue if cost-effective, commercial and residential solar hot water heating programs. The Company will also work with Utah parties to investigate solar program design and deployment issues and opportunities, as well as proceed with a battery 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.*
- *The Company plans to acquire a combined-cycle combustion turbine resource at the Lake Side site in Utah by the summer of 2014 and issue an all-source RFP in late 2011 or early 2012 for acquisition of peaking/intermediate/baseload resources by the summer of 2016. 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 Company plans to acquire up to 1,400 MW of economic front office transactions or power purchase agreements as needed until the beginning of summer 2014. It will continue to 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.*
- *The Company plans to acquire up to 250 MW of cost-effective Class 1 demand-side management programs for 2011-2020, acquire up to 1,200 MW of cost-effective Class 2 programs by 2020, acquire up to 1,200 MW of cost-effective Class 2 programs by 2020, and continue to evaluate Class 3 DSM program opportunities.*
- *In its analysis of resource acquisition paths, the company considers fundamentals-based shifts in natural gas prices, enactment of regulatory policies, and different load trajectories.*
- *PacifiCorp will continue using competitive solicitation processes and will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide clear economic benefits to customers.*

Introduction

PacifiCorp's 2011 IRP action plan identifies the steps the Company will take during the next two to four years to implement the plan, covering the 10-year resource acquisition time frame, 2011-2020. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions and other trigger events during the action plan time horizon that could materially impact resource acquisition strategies.

The resources included in the 2011 IRP preferred portfolio were used to help define the actions included in the action plan, focusing on the size, timing, and type of resources needed to meet load obligations and current and potential future state regulatory requirements. The preferred portfolio resource combination was determined to be the lowest cost on a risk-adjusted basis accounting for cost, risk, reliability, regulatory uncertainty, and the long-run public interest.

The 2011 IRP action plan is based upon the latest and most accurate information available at the time of portfolio study completion. The Company recognizes that the preferred portfolio upon which the action plan is based reflects a snapshot view of the future that accounts for a wide range of uncertainties. The current volatile economic and regulatory environment will likely require near-term alteration to resource plans as a response to specific events and improved clarity concerning the direction of government energy and environmental policies.

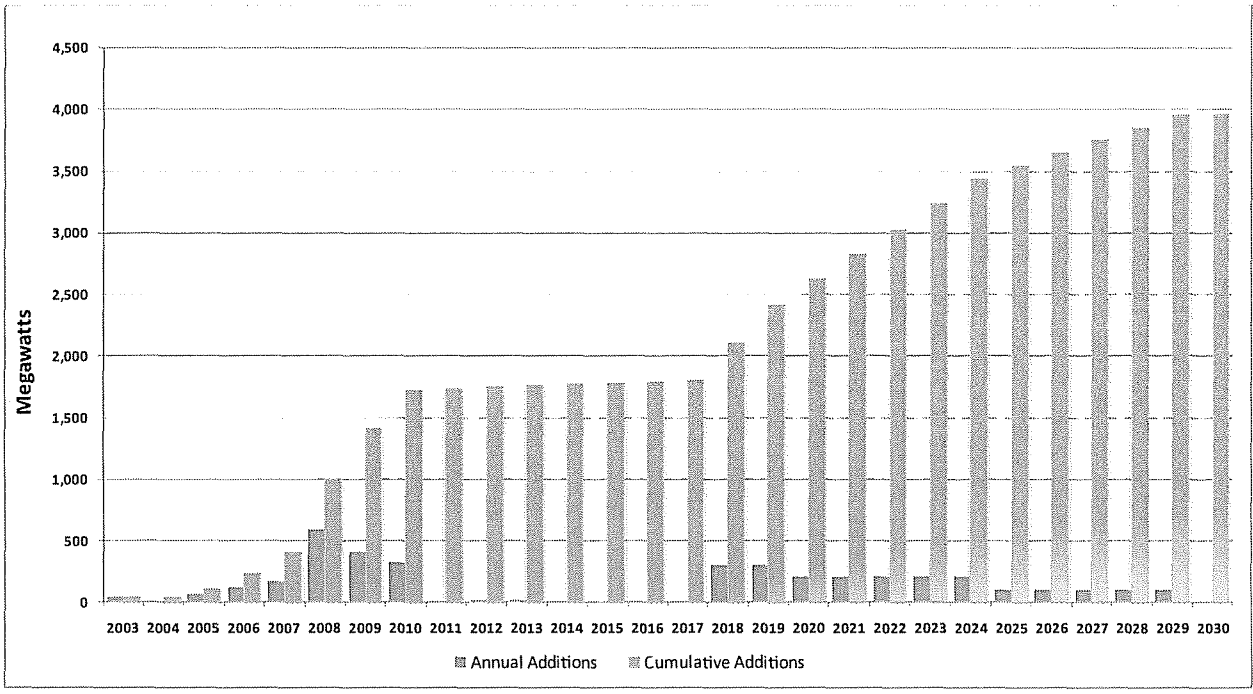
Resource information used in the 2011 IRP, such as capital and operating costs, is consistent with that used to develop the Company's business plan completed in 2010. However, it is important to recognize that the resources identified in the plan are proxy resources and act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resource identified in the plan with respect to resource type, timing, size, cost, and location. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition, and the evaluations will comply with then-current laws and regulatory rules and orders.

In addition to the action plan and acquisition path analysis, this chapter addresses a number of topics associated with resource risk management. These topics include the following:

- Managing carbon risk for existing plants
- The use of physical and financial hedging for electricity price risk
- Managing gas supply risk
- The treatment of customer and investor risks for resource planning

Figure 9.1 shows annual and cumulative additions of renewable installed capacity for 2003 through 2030. As indicated, the Company has already exceeded its MidAmerican Energy Holdings Company and PacifiCorp commitment to acquire 1,400 MW of cost-effective renewable resources by 2015.

Figure 9.1 – Annual and Cumulative Renewable Capacity Additions, 2003-2030



Note: the renewable energy capacity reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.

The Integrated Resource Plan Action Plan

The 2011 IRP action plan, detailed in Table 9.1, provides the Company with a road map for moving forward with new resource acquisitions. The action plan for transmission expansion is provided as Chapter 10.

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**	Wind • *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.* Geothermal • 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. Solar • 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).* Combined Heat & Power (CHP) • *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.

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.

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.

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.

Progress on Previous Action Plan Items

This section describes progress that has been made on previous active action plan items documented in the 2008 Integrated Resource Plan Update report filed with the state commissions on March 31, 2010. Many of these action items have been superseded in some form by items identified in the current IRP action plan.

Action Item 1: Acquire an incremental 890 MW of renewable resource by 2019. Successfully add 230 MW of wind resources in 2010 and 200 MW of wind resources in 2011 that are currently committed to.

- Procure up to an additional 460 MW of cost-effective wind resources for commercial operation, subject to transmission availability, in the 2017 to 2019 time frame via RFPs or other opportunities.
- Monitor geothermal, solar and emerging technologies, and government financial incentives; procure geothermal, 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 and CO_2 emission regulations at the state and federal levels, and adjust the renewable acquisition timeline accordingly.

Status: PacifiCorp acquired 348 MW of wind in 2010. The Company is on track to acquire an additional 93 MW in 2011 and 2012, reaching a total of 490 MW by year end 2012. This positions the Company well towards the goal of 890 MW by 2019 and takes advantage of currently available tax incentives and renewable energy credit sales opportunities to further reduce costs for customers. PacifiCorp completed its geothermal resource study in 2010, identifying a number of commercially viable sites for 2011 IRP modeling and further investigation. PacifiCorp issued its Oregon solar photovoltaic Request for Proposals (RFP) in November 2010 for acquisition of at least 2 MW in 2011.

Action Item 2: Implement a bridging strategy to support acquisition deferral of long-term intermediate/base load resource(s) in the east control area until the beginning of summer 2015, unless cost-effective long term resources such as renewables or thermal plant assets are available and their acquisition is in the best interests of customers.

- Acquire the following resources:
  - Up to 1,250 MW of economic front office transactions on an annual basis as needed through 2015, 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).
  - PURPA Qualifying Facility contracts and cost-effective distributed generation alternatives.
- Resources will be procured through multiple means: (1) the All Source RFP reissued on December 2, 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, or if renewable or thermal plant assets are determined to be cost-effective alternatives.

Status: Based on its updated resource needs assessment and all-source RFP bid evaluation, the Company is proceeding with plans to acquire a gas-fired combined-cycle plant at the Lake Side site in Utah by June of 2014. The Company has so far acquired front office transactions at favorable market prices for 2011 through 2013 (350 MW for 2011, 400 MW for 2012, 300 MW for 2013), and continues to consider entering into power purchase agreements. As noted in Chapter 5, a number of Qualifying Facility contracts have also been signed by the Company.

Action Item 3: Procure through acquisition and/or Company construction long-term firm capacity and energy resources for commercial service in the 2012-2016 time frame.

- The proxy resource included in the 2010 business plan portfolio consists of a Utah wet-cooled gas combined-cycle plant with a capacity rating of 607 MW, acquired by the summer of 2015.
- Procure through the 2008 all-source RFP issued in December 2009.
- The Company submitted a benchmark resource, specified as the addition of a second combined-cycle block at PacifiCorp's Lake Side Plant.
- 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.
- PacifiCorp will reexamine the timing and type of gas resources and other resource changes as part of a comprehensive assumptions update and portfolio analysis to be conducted for the 2008 RFP final short-list evaluation in the RFP approved in Docket UM 1360, the next business plan, and 2008 IRP update.

Status: As noted above, the Company is proceeding with the acquisition of a Utah wet-cooled gas-fired combined-cycle plant located at the Lake Side site. Acknowledgment of the all-source RFP bidder final short list was received by the Oregon Public Utility Commission. PacifiCorp filed an application for pre-approval of the Lake Side 2 combined cycle plant with the Public Service Commission of Utah.

Action Item 4: 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 2019, which are expected to add 86 MW of incremental capacity in the east and 48 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.

- Monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules.

Status: This action item has been updated to reflect planned turbine upgrade projects included in the 2011 business plan. Planned projects now total 65 MW from 2011 through 2021, a drop of 49 MW from the amount reported in the 2008 IRP Update. PacifiCorp filed its second heat rate improvement plan with the Utah Commission in April 2010. This plan increases the 2018 improvement goal by 285 Btu/kWh (213 to 498 Btu/kWh).

Action Item 5: Acquire up to 200 MW of cost-effective Class 1 demand-side management programs for implementation in the 2010-2019 time frame.

- Pursue up to 30 MW of expanded Utah Cool Keeper program participation by 2019; revisit the program's growth assumptions in light of the recent passage of Utah legislation that permits an opt-out program design.
- Pursue up to 100 MW of additional cost-effective class 1 DSM products including commercial curtailment and customer-owned standby generation (55 MW in the east side and 45 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 2010, continue to 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.

Status: The Company exceeded its 2010 Class 1 DSM acquisition goal by 24 MW, achieving 482 MW versus the goal amount of 458 MW. This action item has been superseded by Action Item no. 5 in Table 9.1. Note that Governor Herbert vetoed the legislation permitting an opt-out program design.

Action Item 6: Acquire 900 - 1,000 MW of cost-effective Class 2 programs by 2019, equivalent to about 4.1 to 4.6 million MWh.

- Procure through the currently active DSM RFP and subsequent DSM RFPs

Status: The Company exceeded its 2010 Class 2 DSM acquisition goal by 56,137 MWh, achieving 499,059 MWh versus the goal amount of 442,922 MWh. This action item has been superseded by Action Item no. 6 in Table 9.1.

Action Item 7: 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.

Status: This action item has been superseded by Action Item no. 3 in Table 9.1.

Action Item 8: Planning Process Improvements

- For the next IRP planning cycle, complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level. Use the enhanced model to provide more detailed analysis of potential hard-cap regulation of carbon dioxide emissions and achievement of state or federal emissions reduction goals. Also use the capacity expansion model to evaluate the cost-effectiveness of coal facility retirement as a potential response to future regulation of carbon dioxide emissions.
- 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.
- For the next IRP planning cycle, provide an evaluation of, and continue to investigate, intermediate-term market purchase resources for purposes of portfolio modeling
- Consider developing one or more scenarios incorporating plug-in electric vehicles and Smart Grid technologies.

Status: PacifiCorp successfully implemented the planned System Optimizer enhancements for improved representation of CO_2 and RPS regulatory requirements. Carbon dioxide hard cap scenarios for the first time incorporated assignment of emission rates to spot market system balancing transactions. PacifiCorp used for the first time System Optimizer's plant betterment functionality to evaluate coal plant idling scenarios. Refinements to DSM supply curves included updating the T&D investment deferral credit, applying risk mitigation cost credits to DSM supply curve prices (see Chapter 6), and reclassifying cost bundle breakpoints (also Chapter 6). Ventyx, the model vendor, advised PacifiCorp that the LOLP reliability constraint functionality requires additional design work and is not ready for a production environment. No intermediate-term market purchases were available for evaluation through the Company's all-source RFP. Plug-in electric vehicles and Smart Grid technology scenarios is addressed in Action Item no. 8 in Table 9.1.

Action Item 9: Obtain Certificates of Public Convenience and Necessity and conditional use permits for Utah/Wyoming/Idaho segments of the Energy Gateway Transmission Project to support PacifiCorp loads, 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 and 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.

Status: The Utah Public Service Commission issued a Certificate of Public Convenience and Necessity for the Mona to Oquirrh project in June 2010. PacifiCorp has begun permitting efforts and right of way research for Windstar-Populus project. A contract will be issued during the 4th Quarter of 2011 for right-of-way acquisition, which will begin in 2012. The Company hopes to complete the Environmental Impact Statement process with the Bureau of Land Management in 2012. As with the Windstar-Populus project, PacifiCorp has partnered with Idaho Power to build the Populus to Hemingway segment of Gateway West. The companies hope to complete the Environmental Impact Statement process and all necessary permitting in 2012, and to begin construction as early as 2015. See Chapter 10, Transmission Expansion Action Plan, for more details.

Action Item 10: Complete Utah/Idaho segments of the Energy Gateway Transmission Project to support PacifiCorp loads, regional resource expansion needs, market access, grid reliability, and congestion relief.

Permit and construct a 345 kV line between Populus to Terminal.

Status: PacifiCorp completed the Populus to Terminal project in November 2010. See Chapter 10, Transmission Expansion Action Plan.

Action Item 11: Permit and build Utah segment of the Energy Gateway Transmission Project to support PacifiCorp loads, regional resource expansion needs, access to markets, grid reliability, and congestion relief

Permit and construct a 500 kV line between Mona and Oquirrh.

Status: Right-of-way efforts are ongoing and construction is scheduled to begin in 2011. The Mona to Oquirrh segment is scheduled for completion in 2013, while the Oquirrh to Terminal segment is scheduled for completion in 2014. See Chapter 10, Transmission Expansion Action Plan.

Action Item 12: Permit and build segments of the Energy Gateway Transmission Project to support PacifiCorp loads, 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.

Status: The 2008 IRP Update reported an in-service date range of 2014-2016 for Windstar to Populus, but delays in the BLM's Environmental Impact Statement process have delayed the project resulting in revised plans to complete it in the 2015-2017 timeframe. PacifiCorp hopes to complete all permitting and right of way acquisitions for Sigurd-Red Butte by 2012 and to place the project in-service in 2014. See Chapter 10, Transmission Expansion Action Plan.

Action Item 13: Permit and build Northwest/Utah segments of the Energy Gateway Transmission Project to support PacifiCorp loads, regional resource expansion needs, access to markets, grid reliability, and congestion relief

Permit and construct a 500 kV line between Populus and Hemingway.

Status: The Company has previously estimated an in-service date range of 2014-2018 for the Populus to Hemingway project, but now plans to complete the project in the 2015-2018 timeframe. The delay on the front end of the project is primarily the result of the BLM's delay of the draft Environmental Impact Statement. See Chapter 10, Transmission Expansion Action Plan.

Action Item 14: Permit and build Wyoming/Utah segment of the Energy Gateway Transmission Project to support PacifiCorp loads, regional resource expansion needs, access to markets, grid reliability, and congestion relief

Permit and construct a 500 kV line between Aeolus and Mona

Status: The project is scheduled for completion in the 2017-2019 timeframe. The Company began its public scoping process during the first quarter of 2011. See Chapter 10, Transmission Expansion Action Plan.

Action Item 15: Obtain rights of way and construct the Wallula-McNary line segment.

Status: PacifiCorp has received all state and local permits and is currently pursuing the final federal permits and interconnection at the McNary substation. The line route has been determined and initial line design has been completed. The Company continues to work with property owners and expects to have all necessary rights of way for the project by April 2011. PacifiCorp estimated in its 2008 IRP Update that the line would be constructed and in service by late 2011. However, due to extended lead times required to receive all federal agency approvals, the project is now expected to be completed in the 2012-2013 timeframe. See Chapter 10, Transmission Expansion Action Plan.

Action Item 16: For future IRP planning cycles, include on-going financial analysis with regard to transmission, which includes: a comparison with alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects, the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments and base case segments.

Status: See Chapter 4, Transmission Planning.

Action Item 17: By August 2, 2010, complete a wind integration study that has been vetted by stakeholders through a public participation process.

Status: PacifiCorp completed the wind integration study and distributed it to the public via email and Web site posting on September 1, 2010. The Public Utility Commission of Oregon granted a deadline extension from August 1 to September 1, 2010. The study is included in the 2011 IRP as Appendix I.

Action Item 18: During the next planning cycle, work with parties to investigate carbon dioxide emission levels as a measure for portfolio performance scoring.

Status: PacifiCorp incorporated CO_2 emission levels as a final portfolio screening measure for preferred portfolio selection. See Chapter 7, Modeling and Portfolio Evaluation Approach.

Action Item 19: In the next IRP, provide information on total CO_2 emissions on a year-to year basis for all portfolios, and specifically, how they compare with the preferred portfolio.

Status: Appendix D contains System Optimizer CO_2 emissions on a year-by basis for each portfolio, including the preferred portfolio.

Action Item 20: For the next IRP planning cycle, work with parties to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan, and for which the Company can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.

Status: PacifiCorp conducted a two-phased System Optimizer simulation to test the impact of limiting the model's optimization foresight to 12 years relative to a simulation based on the full 20 years. The results are documented in Chapter 8.

Action Item 21: In the next IRP planning cycle, incorporate assessment of distribution efficiency potential resources for planning purposes.

Status: PacifiCorp is conducting a conservation voltage reduction study, targeting 19 distribution feeders in Washington. The study is expected to be completed by the end of May 2011. Based on preliminary data provided by the contractor for the study, PacifiCorp developed a distribution efficiency resource for testing with the System Optimizer model. Results of the portfolio development testing are provided in Chapter 8. This action item has been superseded by Action Item 6 in Table 9.1.

Acquisition Path Analysis

Resource Strategies

Of most concern from a planning perspective are so called regime shifts in which conditions change abruptly and permanently, sometimes with little or no warning. The Energy Gateway scenario analysis outlined in Chapter 4 considered Incumbent and Green Future scenarios defined by combinations of associated CO_2/natural gas price trajectories and regulatory intervention in the form of a federal RPS requirement (Waxman-Markey renewable energy targets). Other scenarios, similarly defined by a trigger event that causes sustained departure from expectations, are considered for the acquisition path analysis. Specifically, PacifiCorp focuses on fundamentals-based shifts in natural gas prices, enactment of regulatory policies, and different load trajectories. For a specific resource already planned for acquisition, the path analysis also addresses procurement delays.

The path analysis is based on the portfolio development scenario and sensitivity analysis results outlined in Chapter 8, along with additional portfolio simulations conducted with the preliminary preferred portfolio as the starting point. For each trigger event, Table 9.2 lists the associated planning scenario and both short-term (2011-2020) and long-term (2021-2030) resource strategies.

Acquisition Path Decision Mechanism

The Utah Commission requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[77] PacifiCorp's decision mechanism is centered on the business planning and IRP processes, which together constitute the decision framework for making resource investment decisions. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and DSM target-setting/valuation processes. In developing the IRP action plan and path analysis, the Company considers common elements across multiple resource strategies (for example, base levels of each resource type across many least-cost portfolios optimized according to different futures), planning contingencies and resource flexibility, and continuous evaluation of market/regulatory developments and resource options.

Critical to this decision mechanism is the role of the annual business planning process, which determines the impact of resource decisions on overall capital expenditures, customer rates, earnings, cash flows, and financing requirements. The IRP and business plan serve as decision support tools for senior management to determine the most prudent resource acquisition paths for maintaining system reliability and low-cost electricity supplies, and to help address strategic positioning issues. The key strategic issues as outlined in this IRP include (1) addressing regulatory risks in the areas of climate change and renewable resource policies, (2) accounting for price risk and uncertainty in making resource acquisition decisions, (3) load uncertainty, and (4) determining the appropriate level and timing of long-term transmission expansion investments, accounting for the regulatory risks and uncertainties outlined above.

[77] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

Table 9.2 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2011-2020)	Long Term Resource Acquisition Strategy
Increased natural gas prices relative to current expectations, driven by higher oil prices, reduced imports, delayed unconventional gas supply development	Long term 50-60% price increases relative to the Medium forecast.	• Defer the second and third CCCT resources by one to two years if cost-effective relative to other resources. • Consider advanced high-efficiency gas generation technologies, evaluating the trade-off between greater efficiency and higher capital costs and project risks. • Increase energy efficiency resources by 80-100 MW. • Pursue additional renewables-based distributed generation opportunities through PURPA Qualifying Facility contracts.	• Expand acquisition of non-fossil fuel generation resources to additional clean baseload and hybrid renewable/intermittent-storage technologies. If sufficient capacity can be obtained economically, replace or defer on a long-term basis the third CCCT resource. • Work with regulators to step up demonstration/pilot project activity using innovative generation and storage technologies. • Increase reliance on energy efficiency by an incremental 50-200 MW by 2030, depending on carbon regulatory developments and energy efficiency technology advancement.
Decreased natural gas prices relative to current expectations, driven by continued growth of low-cost non-conventional gas supplies, increased LNG imports, and decreased gas demand	Long term 25-30% price decreases relative to Medium forecast.	• Accelerate the third CCCT resource by one to two years if cost-effective relative to other resources. • Defer wind and other renewables acquisition if compliance with state and federal greenhouse gas and renewable standards if not at risk.	• Investigate alternative coal plant utilization strategies for certain units (fuel switching, idling, etc.) depending on cost and compliance impacts of new U.S. EPA emissions control requirements and federal greenhouse gas regulations.
Significant and persistent reduced market purchase availability	Market turmoil, combined with an economic boom, reduces availability and cost-effectiveness of front office transactions along the lines of the market stress test outlined in Appendix H. This stress test assumed an unexpected 50-percent decrease in FOT availability	• Depending on the duration, severity, and breadth of market purchase shortages: – Accelerate procurement of future planned CCCT resources. – Acquire small simple-cycle combustion turbine units through expedited regulatory approval processes. – Lease mobile emergency generators on an annual or seasonal basis. – Pursue an accelerated demand-side management program expansion (e.g.,	• Modify market depth and pricing assumptions as appropriate for future IRP and business plan support modeling. • On a regional planning basis, consider and potentially support an enforceable resource adequacy standard.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2011-2020)	Long Term Resource Acquisition Strategy
	combined with higher gas prices for 2015-2020.	Utah Cool Keeper opt-out provision, price-response programs, implementation of higher-cost energy efficiency and dispatchable load control programs.)	
Federal Renewable Portfolio Standard	A federal RPS is instituted similar to the Waxman-Markey proposal requiring 20% of load to be met with qualifying resources by 2020.	• Accelerate renewables acquisition to as early as 2015 to meet compliance targets. Acquire up to 400 MW by 2018 depending on compliance provisions, or up to 150 MW of geothermal capacity if enabling state cost recovery legislation and regulatory approval for geothermal exploration & development costs is obtained. • Continue to issue renewable RFPs under PacifiCorp's shelf RFP program, and step up consideration of unsolicited proposals and multi-participant projects as opportunities arise. • Increase reliance on energy efficiency programs to take advantage of any energy credits in federal legislation and cost-effectively reduce the overall compliance requirement.	• Evaluate nuclear and carbon capture & retrofit technologies if included as part of a broader clean energy standard. • Adjust transmission construction plans and increase regional transmission coordination efforts to facilitate project development activity.
Continued extension of the federal renewable production tax credit	The federal renewable PTC is extended to at least 2020 at its present level.	• Acquire up to 100 MW of additional wind if the federal PTC is extended beyond 2017. • Consider scenarios for which the PTC is selectively applied to certain renewables (emerging technologies) or phased out over time.	• Evaluate as scenarios
Diminishing Federal Renewable Energy Support	Due to federal budget pressures and a shift in federal spending priorities, the federal renewables PTC expires within the next several years and other incentives phase out in the next five years; no federal renewable standard is	• If there are no carbon reduction regulatory requirements expected, put on hold plans to acquire more wind, barring continuing drops in turbine prices due to improved technology and manufacturing over-capacity. • Revisit the need for Energy Gateway transmission projects; scale back or indefinitely postpone investments depending on the regulatory and market outlook. • Acquire up to 80 MW of geothermal resources (given	• Continue to investigate renewable technology cost-effectiveness and risks through the IRP process for future compliance with existing state RPS requirements.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2011-2020)	Long Term Resource Acquisition Strategy
	forthcoming.	enabling state cost recovery legislation and regulatory approval for geothermal exploration & development costs and favorable project economics) and other cost-effective renewables as a hedge against volatile fuel prices prior to PTC/investment credit expiration.	
CO_2 emission compliance: low to medium cost impact	A federal cap-and-trade program or other CO_2 pricing mechanism is instituted in the 2015-2017 timeframe; prices start at $12-$15/ton and escalate at about 5% annually.	• Adjust timing of renewables acquisition to minimize regulatory compliance costs. The mix of renewables is dependent on gas price expectations, geothermal legislative and regulatory support, and relative economics of technologies. • Depending on specific CO_2 costs and gas prices, step up acquisition of demand-side management programs and high-efficiency distributed generation to help minimize the carbon footprint. • Modify the RFP bid evaluation process (which is based on the IRP portfolio modeling framework) to reflect updated CO_2 regulatory expectations.	• Continue to diversify the resource mix, and take advantage of any CO_2 compliance credits that may be given to these resource types. • Increase reliance on energy efficiency by an incremental 50-200 MW by 2030, depending on inclusion of energy efficiency incentives in comprehensive energy legislation, specific carbon regulations enacted, and energy efficiency technology advancement. • Investigate alternative coal plant utilization strategies for certain units (fuel switching, idling, etc.) depending on cost and compliance impacts of new U.S. EPA emissions control requirements and detailed impact evaluation of federal greenhouse gas regulations.
CO_2 emission compliance: high cost impact	A federal cap-and-trade program or other CO_2 pricing mechanism is implemented with prices starting at $25/ton and escalate at about 7% annually. Alternatively, an emissions hard cap is imposed limiting emissions to 15% below 2005 levels by 2020, and 80% by 2050	• Adjust timing of renewables acquisition to minimize regulatory compliance costs. The mix of renewables is dependent on gas price expectations, geothermal legislative and regulatory support, and relative economics of technologies. • Evaluate the economic and operational impacts of reducing coal plant utilization and increasing natural gas plant utilization as a CO_2 emissions compliance strategy. • Increase energy efficiency resources by up to 100 MW. • Modify the RFP bid evaluation process to reflect updated CO_2 regulatory expectations.	• Increase reliance on energy efficiency by an incremental 50-200 MW by 2030, depending on inclusion of energy efficiency incentives in comprehensive energy legislation, specific carbon regulations enacted, and energy efficiency technology advancement. • Investigate alternative coal plant utilization strategies for certain units (fuel switching, idling, CCCT replacement, carbon capture & retrofit technologies) depending on cost and compliance impacts of new U.S. EPA emissions control requirements and detailed impact evaluation of federal greenhouse

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2011-2020)	Long Term Resource Acquisition Strategy
			gas regulations. • Continue to diversify the resource mix, and take advantage of any CO_2 compliance credits that may be given to these resource types. • Evaluate nuclear if included as part of a broader clean energy standard.
Higher load growth on a sustained basis	1% increase in economic growth drivers sustained through 2030	• Accelerate acquisition of the third CCCT by one to two years (2019 to 2018 or 2017). • Acquire SCCT capacity if cost-effective. • Increase energy efficiency by 50-100 MW. • Accelerate dispatchable load control program capacity. • Acquire additional economic market purchases to maintain planning reserve margins. • If higher load growth can be sustained with aggressive renewables and/or CO_2 regulation, orient incremental capacity additions to a high CO_2 compliance resource strategy.	• Increase energy efficiency by up to another 70 MW by 2030. • Acquire baseload renewables (up to 50 MW) if economic based on government incentives and carbon regulations.
Lower load growth on a sustained basis	1% decrease in economic growth drivers sustained through 2030	• Eliminate/defer the second or third CCCT based on revised load growth projections. • Increase energy efficiency reliance to help defer gas resources if gas prices are anticipated to increase relative to the current Medium forecast.	• Defer gas resources and market purchases as appropriate based on lowered load growth expectations. • Depending on cost and compliance impacts of new U.S. EPA emissions control requirements and federal greenhouse gas regulations, consider coal plant idling strategies for certain units.

Procurement Delays

The main procurement risk is an inability to procure resources in the required time frame to meet the need. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in the 2011 IRP. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or a material change in the market for fuels, materials, electricity, or environmental or other electric utility regulations, may change the Company's entire resource procurement strategy.

Possible paths PacifiCorp could take if there was either a delay in the on-line date of a resource or, if it was no longer feasible or desirable to acquire a given resource, include the following:

- Consider alternative bids if they haven't been released under a current RFP.
- Issue an emergency RFP for a specific resource.
- Move up the delivery date of a potential resource by negotiating with the supplier/developer.
- Rely on near-term purchased power and transmission until a longer-term alternative is identified, acquired through PacifiCorp's mini-RFPs or sole source procurement.
- Install temporary generators to address some or all of the capacity needs.
- Temporarily drop below the 13 percent planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

Resource differences between the 2011 IRP and the 2011 business plan approved in December 2010 relate primarily to the amount of energy efficiency. For DSM resources, receipt and modeling of the final Cadmus supply curves occurred after the business plan was completed. The IRP modeling thus reflects a more current view of DSM efficiency potentials and costs that will be incorporated in portfolio modeling to support preparation of the Company's 2012 business plan.

The amount of wind in the 2011 IRP preferred portfolio reflects the comprehensive portfolio scenario analysis, stochastic risk analysis, and clean energy policy/regulatory compliance risk assessment conducted in December 2010 through February 2011, after the business plan was approved. In both the 2011 business plan and 2011 IRP, PacifiCorp shifted Wyoming wind capacity from 2017 to 2018 in recognition of the revised planned timeline for Energy Gateway West. The overall wind capacity in the 2011 IRP preferred portfolio decreased by 60 MW in the 2018-2020 period relative to the 2011 business plan.

Table 9.3 compares the 2011 IRP preferred portfolio with the 2008 IRP Update portfolio[78] for the 10 years covered by both portfolios (2011-2019), indicating year by year capacity differences by major resource categories (yellow highlighted table). The major resource changes include:

- Three CCCT resources included in the portfolio by 2019 rather than two, driven by an increased planning reserve margin (12 to 13 percent), lowered expectations for irrigation load control program capacity, and lower gas prices.
- Significantly more energy efficiency and dispatchable load control—312 MW and 79 MW, respectively.

[78] The 2008 IRP Update report is available on PacifiCorp's IRP Web site: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2008IRPUpdate/PacifiCorp-2008IRPUpdate_3-31-10.pdf

Table 9.3 – Portfolio Comparison, 2011 Preferred Portfolio versus 2008 IRP Update Portfolio

2011 IRP Preferred Portfolio

	Capacity (MW)											Total
Resource	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2011-2019**
Coal Plant Turbine Upgrades		12	19	6	-	-	18	-	8	-	-	63
Gas		-	-	-	625	-	597	-	-	475	-	1,697
Wind		-	-	-	-	-	-	-	300	300	200	600
Other renewable (Oregon solar)		4	9	9	7	7	4	4	4	-	-	49
DSM, Class 1		6	70	57	20	97	-	-	-	-	-	250
DSM, Class 2		108	114	110	118	122	124	126	120	122	125	1,064
Distributed Generation		5	5	5	5	5	5	5	5	5	5	47
East - PPA		-	-	-	-	-	-	-	-	-	-	-
Total Long Term Resources		**134**	**217**	**187**	**776**	**232**	**749**	**136**	**437**	**902**	**330**	**3,769**
East - Firm Market Purchases		200	368	618	590	649	325	372	517	300	545	
West - Firm Market Purchases		150	871	811	600	500	450	450	450	395	450	
Firm Market Purchases		**350**	**1,240**	**1,429**	**1,190**	**1,149**	**775**	**822**	**967**	**695**	**995**	

Difference - 2011 IRP Preferred Portfolio less 2008 IRP Update

	Capacity (MW)											Total
Resource	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2011-2019**
Coal Plant Turbine Upgrades	(20)	(8)	19	4	-	(11)	(31)	(12)	-	(12)	-	(51)
Gas	-	-	-	-	625	(607)	597	-	(536)	475	-	554
Wind	(247)	(200)	-	-	-	-	-	(160)	200	100	-	(60)
Other renewable (Oregon solar)	-	2	7	7	6	6	4	4	4	-	-	40
DSM, Class 1	(43)	(10)	33	19	5	95	-	-	-	-	-	142
DSM, Class 2	(105)	3	9	3	10	36	37	47	43	41	43	230
Distributed Generation	-	5	5	5	5	5	5	5	5	5	5	47
East - PPA	-	-	(200)	-	-	-	-	-	-	-	-	(200)
Total Long Term Resources	(414)	**(207)**	**(126)**	**38**	**651**	**(476)**	**612**	**(115)**	**(284)**	**609**	**48**	**702**
East - Firm Market Purchases	-	200	168	280	71	349	25	22	170	(50)	195	
West - Firm Market Purchases	-	150	467	217	(104)	5	(173)	(158)	161	(49)	(184)	
Firm Market Purchases	-	**350**	**635**	**496**	**(33)**	**355**	**(148)**	**(136)**	**331**	**(99)**	**11**	

2008 IRP Update (2010 Business Plan)

	Capacity (MW)											Total
Resource	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2011-2019**
Coal Plant Turbine Upgrades	20	20	-	2	-	11	49	12	8	12	-	114
Gas	-	-	-	-	-	607	-	-	536	-	-	1,143
Wind	247	200	-	-	-	-	-	160	100	200	200	660
Other renewable (Oregon solar)	-	2	2	2	2	2	-	-	-	-	-	9
DSM, Class 1	43	16	37	38	15	3	-	-	-	-	-	108
DSM, Class 2	105	105	105	107	108	86	88	79	77	80	82	834
Distributed Generation	-	-	-	-	-	-	-	-	-	-	-	-
East - PPA	-	-	200	-	-	-	-	-	-	-	-	200
Total Long Term Resources	**414**	**342**	**344**	**149**	**125**	**708**	**136**	**251**	**721**	**292**	**282**	**3,068**
East - Firm Market Purchases	-	-	200	338	519	300	300	350	347	350	350	
West - Firm Market Purchases	-	-	404	594	704	494	623	608	289	444	634	
Firm Market Purchases	-	-	**604**	**932**	**1,223**	**794**	**923**	**958**	**636**	**794**	**984**	

Resource Procurement Strategy

To acquire resources outlined in the 2011 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with the then-current law, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide clear economic benefits to customers. Regardless of the method for acquiring resources, the Company will use its IRP models to support resource evaluation as part of the procurement process, with updated assumptions including load forecasts, commodity prices, and regulatory requirement information available at the time that the resource evaluations occur. This will ensure that the resource evaluations account for a long-term system benefit view in alignment with the IRP portfolio analysis framework as directed by state procurement regulations, and with business planning goals in mind.

The sections below profile the general procurement approaches for the key resource categories covered in the action plan: renewables, demand-side management, thermal plants, distributed generation, and market purchases.

Renewable Resources

The Company uses a shelf RFP as the primary mechanism under which the Company will issue subsequent RFPs to meet most of the renewable resource acquisition goals over the IRP action plan and business planning horizons. The shelf RFP, to be re-issued on a periodic basis, will allow the Company to react effectively to power supply market developments and changes in the status of RPS requirements, the production tax credit, other financial incentives, and CO_2 legislation. The Company will seek both cost-effective conventional and emerging renewable technologies through the RFP process, including those coupled with energy storage. Qualifying Facilities under the Public Utilities Regulatory Policy Act (PURPA), at least 10 MW in size, are also treated as eligible resources under this particular RFP program.

The Company will also pursue renewable resources through means other than the shelf RFP in recognition that strong competition for renewable projects, and the dynamic nature of renewable construction and equipment markets, will require the Company to respond quickly and efficiently as resource opportunities arise. Other procurement strategies that PacifiCorp will pursue in parallel include bilateral negotiations, PURPA contracting, and self-development.

Demand-side Management

PacifiCorp uses a variety of business processes to implement DSM programs. The outsourcing model is preferred where the supplier takes the performance risk for achieving DSM results (such as the Cool Keeper program). In other cases, PacifiCorp manages the program and contracts out specific tasks (such as the Energy FinAnswer program). A third method is to operate the program completely in-house as was done with the Idaho Irrigation Load Control program. The business process used for any given program is based on operational expertise, performance risk and cost-effectiveness. With some RFP's, PacifiCorp developed a specific program design, and put that design out to competitive bid. In other cases, as with the 2008 DSM RFP issued in November 2008, PacifiCorp opened up bidding to many types of Class 1, 2, and 3 programs and design options.

To support the DSM procurement program, the IRP models are used for resource valuation purposes to gauge the cost-effectiveness of programs identified for procurement shortlists. For Class 2 programs, PacifiCorp performs a "no cost" load shape decrement analysis to derive program values using its stochastic production cost model, *Planning and Risk*, similar to what was done for the 2008 IRP. (Although the supply curve modeling approach used for Class 1 and Class 2 DSM programs can provide a gross-level indication of program value, an avoided-cost type of study is necessary to pinpoint precise values suitable for cost-effectiveness assessment.) The load shape decrement analysis will be published as a supplement to this IRP once completed.

Thermal Plants and Power Purchases

Prior to the issuance of any supply-side RFP, PacifiCorp will determine whether the RFP should be "all-source" or if the RFP will have limitations as to the amount, proposal structure(s), fuel type, or other resource attributes. The Company expects to issue an all-source RFP to support acquisition of major resources after 2014.

Company benchmark resources will also be determined prior to an RFP being issued and may consist of a self-developed resource option or a build own transfer arrangement. As with other resource categories, the IRP models will be used for bid evaluation, and will reflect the latest market prices, load forecasts, regulatory policies, and other updated information as appropriate.

Distributed Generation

Distributed generation, such as CHP and solar hot water heating, were found to be cost-effective resources in the context of IRP portfolio modeling. PacifiCorp's procurement process will continue to provide an avenue for such new or existing resources to participate. These resources will be advantaged by being given a minimum bid amount (MW) eligibility that is appropriate for such an alternative, but that is also consistent with PacifiCorp's then-current and applicable tariff filings (QF tariffs for example).

PacifiCorp will continue to participate with regulators and advocates in legislative and other regulatory activities that help provide tax or other incentives to renewable and distributed generation resources. The Company will also continue to improve representation of distributed generation resource in the IRP models.

Assessment of Owning Assets versus Purchasing Power

As the Company acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, the Company would be in a better position to control costs, make life extension improvements, use the site for additional resources in the future, change fueling strategies or sources, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at cost as long as it remains economic. In addition, by owning a plant, the Company can hedge itself from the uncertainty of relying on purchasing power from others. On the negative side, owning a facility subjects the Company and customers to the risk that the cost of ownership and operation exceeds expectations, the cost of poor performance, fuel price risk, and the liability of reclamation at the end of the facility's life.

Depending on contract terms, purchasing power from a third party in a long term contract may help mitigate the risk of cost overruns during construction and operation of the plant, may mitigate some cost and performance risks, and may avoid any liabilities associated with closure of the plant. Short-term purchased power contracts could allow the Company to defer a long term resource acquisition. On the negative side, a long-term purchase power contract relinquishes control of construction cost, schedule, ongoing costs and compliance to a third party, and exposes the buyer to default events and contract remedies that will not likely cover the potential negative impacts. For example, a purchase power contract could terminate prior to the end of the term, requiring the Company to replace the output of the contract at then current market prices. In addition, the Company and customers do not receive any of the savings that result from management of the asset, nor do they receive any of the value that arise from the plant after the contract has expired. Finally, credit rating agencies impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation can affect the Company's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

Carbon dioxide reduction regulations at the federal, regional, or state levels would prompt the Company to continue to look for measures to lower CO_2 emissions of existing thermal plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures would be cost-effective and practical from operational and regulatory perspectives. As noted earlier in the IRP, prospective federal emission control rules will also impact coal plant utilization and investment decisions.

For a cap-and-trade system, examples of factors affecting carbon compliance strategies include the allocation of free allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. To lower the emission levels for existing thermal plants, options include changing the fuel type, repowering with more efficient generation equipment, lowering the plant heat rate so it is more efficient, and adoption of new technologies such as CO_2 capture with sequestration when commercially proven. Indirectly, plant carbon risk can be addressed by acquiring offsets in the form of renewable generation and energy efficiency programs. Under an aggressive CO_2 regulatory environment, and depending on fuel costs, coal plant idling and replacement strategies may become tenable options.

High CO_2 costs would shift technology preferences both for new resources and existing resources to those with more efficient heat rates and also away from coal, unless carbon is sequestered. There may be opportunities to repower some of the existing coal fleet with a different less carbon-intensive fuel such as natural gas, but as a general rule, coal units will continue to use the existing coal technology until it is more cost-effective to replace the unit in total. A major issue is whether new technologies will be available that can be exchanged for existing coal economically.

Fuel switching and dual-fueling provide some limited opportunities to address emissions, but will require both capital investment and an understanding of the trade-offs in operating costs and risks. While these options would provide the Company a means to lower its emission profile, such options would be extremely expensive to implement unless there is a high carbon emission penalty to justify them.

Managing Gas Supply Risk

Adding natural gas generating resources to PacifiCorp's system requires an understanding of the fuel supply risks associated with such resources, and the application of prudent risk management practices to ensure the availability of sufficient physical supplies and limit price volatility exposure. The risks discussed below include price, availability, and deliverability.

Price Risk

PacifiCorp manages price risk through a documented hedging strategy. This strategy involves nearly fully hedging price risk in the nearest 12-month forecast period and hedging less of the exposure each year beyond that through year four. Near-term prices for forecasted volumes are nearly fully hedged to add price certainty to near term planning horizons, budgets, and rate case filings. Further out, where plans and budgets are less certain, PacifiCorp considers its most recent ten-year business plan, current market fundamentals, credit risk, collateral funding, and regulatory risk in making hedging decisions. PacifiCorp balances the benefit of hedging that plan's price assumptions with prudent risk management for its ratepayers and shareholders. PacifiCorp hedges price risk through the use of financial swap transactions and/or physical transactions. These transactions are executed with various counterparties that meet PacifiCorp's credit and contractual requirements.

Availability Risk

Availability risk refers to the risk associated with having adequate natural gas supply in the vicinity of contemplated generating assets. PacifiCorp purchases physical supply on a forward basis achieving contractual commitments for supply. The Company also relies on its ability to purchase physical supplies in the future to meet requirements. This second approach subjects PacifiCorp to price risk resulting from swings in supply-demand balances, as well as the risk that natural gas production in a producing region ceases regardless of price. It is reasonable that a region-wide cease in production, given reserve estimates, could only be brought about by extreme and unforeseen events such as natural disaster or regulatory moratoriums on the production or consumption of natural gas—events that long-term supply commitments would not counteract. Index prices are designed to reflect the prevailing cost of supply at various delivery locations. As described above, PacifiCorp hedges its exposure to changes in those index prices, thereby allowing for procurement of supply at floating index prices or waiting to acquire supply when requirements estimates are more accurate and the premiums for longer-term commitments are no longer demanded by suppliers.

Deliverability Risk

Deliverability risk refers to the risk associated with transporting natural gas supply from supply locations to generating facilities. The 2011 IRP accounts for the cost of natural gas transportation service required to fuel gas plants, and uses existing tariff pipeline-defined transportation capacity and transportation costs in evaluating the need, timing, and location of new natural gas-fired generating plants. More specifically, the 2011 IRP uses existing maximum tariff rates for demand charges, volumetric costs, and reimbursement of fuel and lost/unaccounted natural gas. These tariff rates are developed through cost of service filings with appropriate regulators—the FERC for interstate pipelines and relevant state regulators for intrastate pipelines. By definition, rates are developed based on cost of service of existing operations, without consideration for maintenance and operations of future expansions. The result of this is that the 2011 IRP assumes that the economics of a new natural gas fired generator reflect the current cost of service for existing natural gas transportation facilities; whereas, the cost of any new natural gas transportation capacity is dependent on the volumetric size of the new capacity, and prevailing costs of construction, maintenance, and operations (e.g. steel, labor, financing).

Also, the 2011 IRP accounts for the availability of natural gas transportation service required to fuel new electricity generating facilities. In selecting a gas-fired resource, the implicit assumption is made that natural gas transportation infrastructure exists or will be built. This is a reasonable assumption if one further assumes that the construction of new pipeline facilities is a function of cost, which is addressed above.

PacifiCorp manages this transportation cost through two transaction types: transportation service agreements and delivered natural gas purchases:

- PacifiCorp enters into transportation service agreements that offer PacifiCorp the right to ship natural gas from prolific production basins or liquidly traded "hubs" to generating assets. Natural gas hubs exist where a large volume of production is gathered and delivered into a large interstate pipeline or where large pipelines intersect. These hubs lead to liquidly traded markets as the movement of gas from one transporting pipeline to another lead to a large number of willing buyers and sellers.

- PacifiCorp purchases natural gas delivered to generating plants and/or hubs. This approach pushes the deliverability risk to the supplier by contractually committing it to making necessary supply and/or transportation arrangements.

PacifiCorp is confident that the risks associated with fueling current and prospective natural gas fueled generation can be effectively managed. Risk management involves ongoing monitoring of the factors that affect price, availability, and deliverability. While prudence warrants the monitoring of many factors, some issues that PacifiCorp needs to pay particular attention to, given today's market, include the following:

- Potential counterparties need to be continually monitored for their creditworthiness and long-term viability, especially given the current economic downturn.
- Environmental concerns could impact natural gas prices; examples include carbon regulation and increased focus on the chemicals used for hydraulic fracturing for shale gas production. PacifiCorp continues to monitor the regulatory environment and its potential impact on natural gas pricing.
- As production grows in the Rocky Mountains, so does the transportation infrastructure. PacifiCorp continues to monitor this activity for risks and opportunities that new pipeline infrastructure may yield.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the 2011 IRP. Capital expenditures continue to increase, driven by the need for infrastructure investment to support loads and maintain reliable electricity supplies, and the effects of cost inflation. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continues to be government actions related to CO_2 emissions and renewable resources. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of CO_2 emission and renewable standard compliance rules.

To address these risks, the Company evaluates resources in the IRP and for competitive procurements using a range of CO_2 prices consistent with the scenario analysis methodology adopted for the Company's IRP portfolio evaluation process. The Company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. As noted in the sections that describe the derivation of the preferred portfolio, augmenting the portfolio with additional wind resources represents the most effective regulatory risk mitigation measure at the present time, along with a significant increase in demand-side management resource acquisition. The extent to which future regulatory policy shifts do not align with the Company's resource investments determined to be prudent by state commissions is a risk borne by customers.

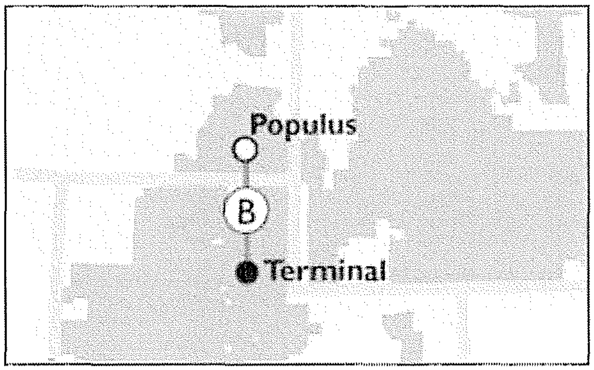
CHAPTER 10 – TRANSMISSION EXPANSION ACTION PLAN

Chapter Highlights

- *PacifiCorp is well underway in the rating, permitting and construction of its Energy Gateway transmission investment plan. Since the original announcement of Energy Gateway in May 2007, PacifiCorp has emphasized that significant new transmission capacity is needed to adequately serve its customers' load and growth needs for the long-term.*
- *In November 2010, the Company placed into service the first major segment of Energy Gateway – the double circuit 345 kV Populus to Terminal line – ahead of schedule and within budget. This line is a key segment of Energy Gateway Central, which ultimately will connect with and enable Gateway West and Gateway South to achieve their full 1,500 MW capacity rating.*
- *PacifiCorp requests regulatory acknowledgement of the Energy Gateway projects scheduled to be in-service in 2014 or sooner. These projects include Wallula to McNary (Segment A), scheduled to be in service 2012-2013; Mona to Oquirrh and Oquirrh to Terminal (Segment C), scheduled to be in service 2013 and 2014, respectively; and Sigurd to Red Butte (Segment G), scheduled to be in service 2014.*
- *PacifiCorp provides as information only an overview of the Energy Gateway segments planned for completion after 2014. These projects include Windstar to Populus (Segment D), scheduled to be in service 2015-2017; Populus to Hemingway (Segment E), scheduled to be in service 2015-2018; and Aeolus to Mona (Segment F), scheduled to be in service 2017-2019.*
- *PacifiCorp also provides a status update on its planned Hemingway to Captain Jack project (Segment H). The Company is considering the prudence of this project in light of other proposed lines, including Idaho Power's Boardman to Hemingway project and Portland General Electric's proposed Cascade Crossing line between Boardman and the Salem, Oregon area. PacifiCorp is exploring potential joint-development opportunities on these projects and, should the customer and system benefits of these potential partnerships exceed those of the Hemingway to Captain Jack project, the Company will pursue these joint development opportunities in place of Hemingway to Captain Jack.*

Introduction

PacifiCorp is well underway in the rating, permitting and construction of its expansive Energy Gateway transmission investment plan. Since the original announcement of Energy Gateway in May 2007, and as discussed further in Chapter 4, PacifiCorp has emphasized that significant new transmission capacity is needed to adequately serve its customers' load and growth needs for the long-term.

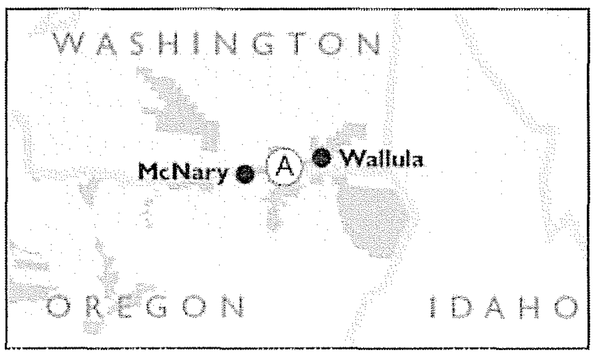


In November 2010, the Company completed and placed into service the first major segment of Energy Gateway – the double circuit 345 kV Populus to Terminal line – ahead of schedule and within budget. This line is a key segment of Energy Gateway Central, which ultimately will connect with and enable Gateway West and Gateway South to achieve their full 1,500 MW capacity rating. Construction on the Mona to Oquirrh line – the other major segment of Gateway Central – is scheduled to begin in 2011, with an expected 2013 in-service date. These and other Energy Gateway segments are detailed further in the Gateway Segment Action Plans section below. The in-service dates provided in the following section are based on optimal timing of transmission needs and best efforts to complete construction, and are subject to change based on permitting, environmental approvals and construction schedules.

Transmission Additions for Acknowledgement

PacifiCorp requests regulatory acknowledgement of the Energy Gateway projects scheduled to be in-service in 2014 or sooner. These projects are detailed below. As the IRP is a public document, however, the Company has not provided in this document confidential financial data related to these projects. PacifiCorp welcomes, as it has in the past, opportunities to discuss additional project details as appropriate to support regulatory acknowledgment of this IRP.

Wallula to McNary (Energy Gateway Segment A)



This project was originally planned as a 56-mile, single circuit 230 kV transmission line connecting PacifiCorp's existing substations at Walla Walla and Wallula, Washington, and Bonneville Power Administration's McNary substation near Umatilla, Oregon. The initial target completion date was 2010; however, the project was put on hold to ensure that it was still the most cost-effective option for our customers in light of evolving regional transmission plans and potential generation development in the area.

In 2009, PacifiCorp received transmission service requests that require the Company to proceed with the Wallula to McNary portion of the Walla Walla to McNary project. This segment consists of approximately 30 miles of single circuit 230 kV line on a 125-foot right of way, and will provide the capacity to add new energy to the system, improve service to customers and improve the reliability of the regional transmission system.

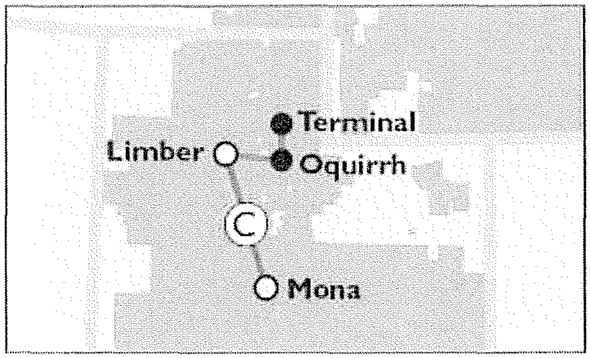
The Wallula to McNary line is needed for several reasons, but primarily to enable the Company to meet current and projected demand in its service area, to address energy constraints on the system and facilitate the transmission of generation resources from remote locations to customer load centers. PacifiCorp's transmission system in the Walla Walla area currently operates at full capacity, and the Company has informed several project developers that their proposed projects could not be interconnected to the system without additional infrastructure. To date, PacifiCorp has entered into two transmission service contracts for service from Wallula to McNary to move a total of 120 megawatts of generation resources to market. The Company has received additional customer requests for interconnection and transmission service on this path, and pursuant to Federal Energy Regulatory Commission policy, public utilities are required to expand and enlarge their transmission systems to reliably provide service to customers and to facilitate the interconnection of generation and transmission service requests.

In Addition, PacifiCorp committed to certain transmission system improvements as part of the settlement agreement approving its acquisition by MidAmerican Energy Holdings Company. Acquisition Commitment 34c requires the Company to establish a link between Walla Walla and Yakima and/or reinforce the line between Walla Walla and the Mid Columbia bus. The commitment also provided that, in the event further review showed such a project to not be cost-effective, optimal for customers or able to be completed by the target date, an alternative with comparable system benefits may be proposed. PacifiCorp performed necessary reviews and determined that a more feasible option would be to construct a line from McNary to Walla Walla, and as explained in the Overview section above, the Company is proceeding with the Wallula to McNary portion of the project at this time.

PacifiCorp has received all state and local permits and is currently pursuing the final federal permits and interconnection at the McNary substation. The line route has been determined and initial line design has been completed. The Company continues to work with property owners and expects to have all necessary rights of way for the project by April 2011. PacifiCorp estimated in its 2008 IRP Update that the line would be constructed and in service by late 2011. However, due to extended lead times required to receive all federal agency approvals, the project is now expected to be completed in the 2012-2013 timeframe.

The remaining section from Wallula to Walla Walla is not currently scheduled to proceed but will remain under review for future consideration.

Mona to Oquirrh and Oquirrh to Terminal (Energy Gateway Segment C)



To meet increasing customer need for electricity, PacifiCorp will construct the Mona to Oquirrh and Oquirrh to Terminal transmission projects in Utah. The Mona to Oquirrh project consist of a single circuit 500 kV line that will run approximately 69 miles between the new Clover substation to be built near the existing Mona substation in Juab County to the new Limber substation to be constructed in Tooele County; and a double circuit 345 kV line extending approximately 31 miles between the Limber substation and the existing Oquirrh substation in West Jordan. The Oquirrh to Terminal project consists of a double circuit 345 kV line running approximately 14 miles between the Oquirrh substation and the Terminal substation.

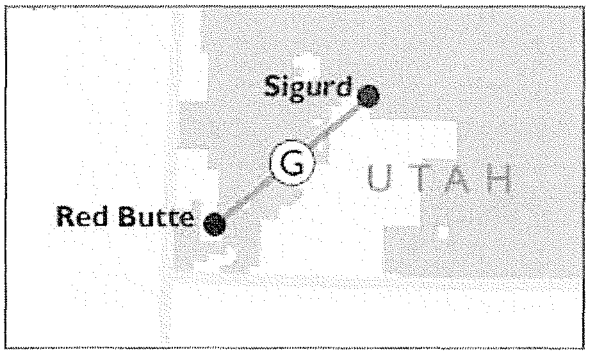
The existing transmission system has limited capability to deliver energy into the largest load center in Utah – the Wasatch Front area (including Salt Lake, Utah, Tooele, Davis, Weber, Cache, and Box Elder Counties). The Mona substation is a critical hub through which power is imported from PacifiCorp's southern intertie lines, and it also serves as an important interconnection point with Deseret Power's Bonanza generating facility and Intermountain Power Agency's Intermountain Power Project. Capacity north of the Mona substation is fully subscribed and constrained, and additional capacity is required in order for PacifiCorp to continue to meet its load service obligations.

In addition to meeting our customers' future energy requirements, these projects are key to maintaining the Company's compliance with mandated North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability and performance standards as necessary during normal system operations and during certain transmission system and generation plant outage conditions.

The Utah Public Service Commission issued a Certificate of Public Convenience and Necessity for the Mona to Oquirrh project in June 2010, and PacifiCorp has obtained all of the local conditional use permits required for the project. The Bureau of Land Management ("BLM") published its Final Environmental Impact Statement in April 2010 and the Record of Decision was posted in February 2011. Right-of-way efforts are ongoing and construction is scheduled to begin in 2011. The Mona to Oquirrh segment is scheduled for completion in 2013 and Oquirrh to Terminal is scheduled for completion in 2014.

Sigurd to Red Butte (Energy Gateway Segment G)

The Sigurd to Red Butte project, part of Gateway South, is a single circuit 345 kV line that runs approximately 160 miles between the Sigurd substation near Richfield, Utah, and an expanded Red Butte substation near Central in Washington County. When completed in 2014, it provides a critical path to meet load obligations and maintain transmission capacity on the TOT2C path for contracted point-to-point service.



The capacity of the southwest Utah transmission system, including the existing Sigurd to Three Peaks to Red Butte 345 kV transmission line, is fully utilized and cannot currently provide adequate service under all expected operating conditions. Loads in southwestern Utah are forecasted to surpass the capabilities of the existing transmission system. Without the project, peak load in southwestern Utah cannot be reliably served during transmission line outages or major equipment contingencies. New transmission facilities must be constructed to provide reliable capacity for load service. The Sigurd to Red Butte transmission project is needed to support both short and long term energy demands and will strengthen the overall reliability of the Company's existing transmission system.

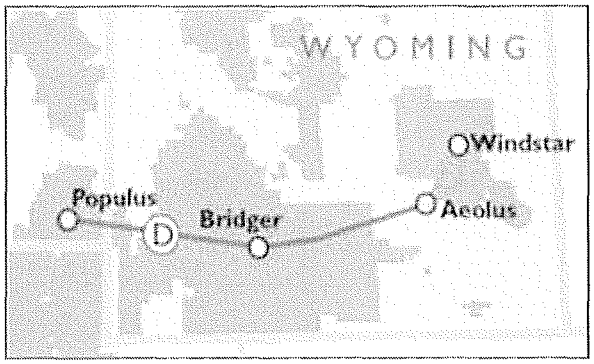
In addition to meeting demand and supporting electrical loads in southwestern Utah, the Sigurd to Red Butte project will also improve the transmission system's ability to transport energy into southwest and central Utah, and to high growth urban areas in and around Salt Lake City and along the Wasatch Front. As with other planned Energy Gateway projects, the Sigurd to Red Butte project is also key to maintaining the Company's compliance with mandated North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability and performance standards during normal system operations and system outage conditions.

The Bureau of Land Management ("BLM") has been designated as the lead agency in the federal environmental review process. The BLM is currently developing an environmental impact statement ("EIS") on the Company's right of way application, a process that began in December 2008. A draft EIS is anticipated to be published for public comment during the 3rd Quarter of 2011, followed by the issuance of a final EIS during the second quarter of 2012. The Company anticipates that the BLM will issue the Record of Decision during the fourth quarter of 2012. At the conclusion of this process the BLM and the U.S. Forest Service will issue a right-of-way grant to build the proposed transmission line on federal property.

PacifiCorp hopes to complete all permitting and right of way acquisitions by 2012 and to place the project in-service for customers in 2014.

Transmission Additions for Information Only

Segment D – Windstar to Populus (Gateway West)

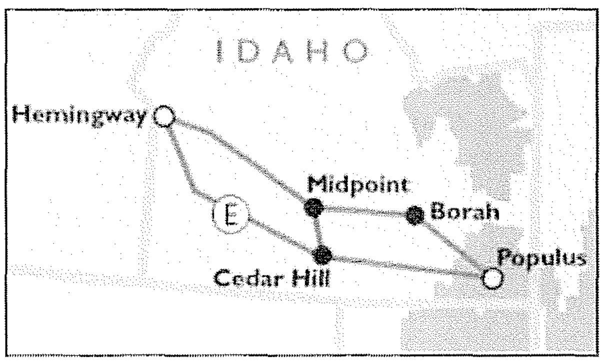


The Windstar to Populus project is the first of two major segments of Gateway West, and consists of three key sections: (i) two single circuit 230 kV lines that will run approximately 82 and 72 miles respectively between the recently constructed Windstar substation in eastern Wyoming and the Aeolus substation to be constructed near Medicine Bow, Wyoming; (ii) a single circuit 500 kV line running approximately 141 miles from the Aeolus substation to a new annex substation near the existing Bridger substation in western Wyoming; and (iii) a single circuit 500 kV line running approximately 205 miles between the new annex substation and the recently constructed Populus substation in southeast Idaho. PacifiCorp has partnered with Idaho Power to build the Windstar to Populus project, which will improve access to existing and new generating resources, including wind, and delivery of these resources to both utilities' customers.

As stated in Chapter 4, PacifiCorp has begun permitting efforts and right of way research for this project. A contract will be issued during the 4th Quarter of 2011 for right-of-way acquisition, which will begin in 2012. The Company hopes to complete the Environmental Impact Statement process with the Bureau of Land Management in 2012. The 2008 IRP Update reported an in-service date range of 2014-2016 for Windstar to Populus, but delays in the BLM's EIS process have delayed the project resulting in revised plans to complete it in the 2015-2017 timeframe.

The Windstar to Populus project, and Gateway West in general, represents a significant improvement in transfer capability from one of the richest areas of diverse resources in the West, a region that currently lacks new export capacity due to severe transmission constraints.

Segment E – Populus to Hemingway (Gateway West)

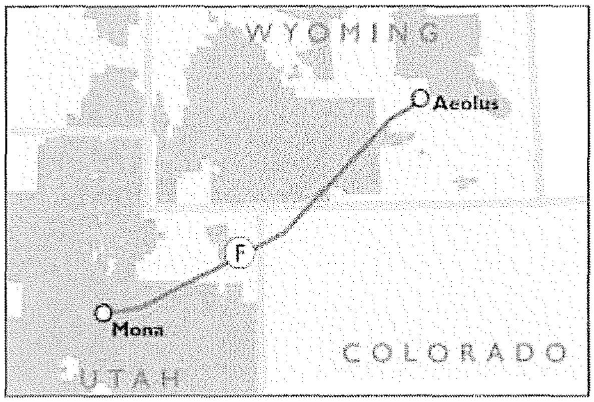


The Populus to Hemingway project is the second of two major segments of Gateway West. The project consists primarily of two single circuit 500 kV lines that run approximately 300 miles each through southern Idaho, from the Populus substation near Downey to a new Hemingway substation located south of Boise between the towns of Melba and Murphy The southern line is planned to connect midway to the new Cedar Hill substation southeast of Twin Falls; the northern line will connect midway to both the Borah substation near Pocatello and the Midpoint substation south of Shoshone; and an additional single circuit 500 kV line will be built connecting the Cedar Hill and Midpoint substations.

As with the Windstar to Populus project, PacifiCorp has partnered with Idaho Power to build the Populus to Hemingway segment of Gateway West. The companies hope to complete the Environmental Impact Statement process and all necessary permitting in 2012, and to begin construction as early as 2015. The Company has previously estimated an in-service date range of 2014-2018 for the Populus to Hemingway project, but now plans to complete the project in the 2015-2018 timeframe. The delay on the front end of the project is primarily the result of the BLM's delay of the draft EIS.

Once completed, the Populus to Hemingway project will enable PacifiCorp and Idaho Power to access existing and new generating resources and deliver power from these sources to customers throughout the region.

Segment F – Aeolus to Mona (Gateway South)

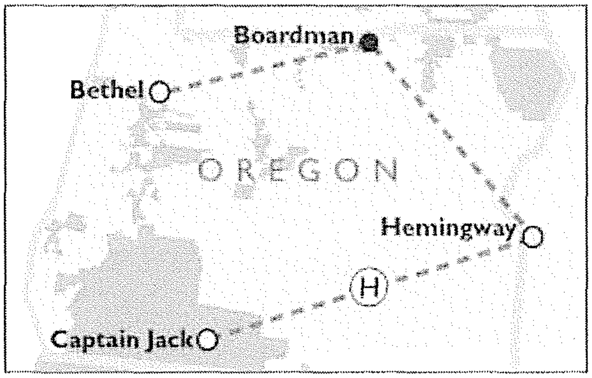


The Aeolus to Mona project is the principal segment of Gateway South and a critical component of the Energy Gateway project overall. The project consists of a single-circuit 500 kV line that runs approximately 395 miles between the Aeolus substation near Medicine Bow, Wyoming, and the Mona substation in central Utah.

The project is scheduled for completion in the 2017-2019 timeframe, and the Company began its public scoping process during the first quarter of 2011. Once complete, the Aeolus to Mona project will connect Gateway West and Gateway Central, providing path rating support to these segments, improving system reliability and operational flexibility for the bulk electric network.

Energy Gateway South, as originally planned, included a single circuit 500 kV line continuing from the Mona substation southwest to the Crystal substation north of Las Vegas, Nevada. As discussed under "Energy Gateway Priorities" in Chapter 4 – *Transmission Planning*, PacifiCorp included in its original Energy Gateway announcement the potential for "upsizing" the project to address regional needs, including the Mona to Crystal segment and higher-capacity build options of other segments. While there was significant interest by third parties to participate in the Gateway South project, there was a lack of requisite financial commitment needed to maximize the project's capacity for broader regional needs, and PacifiCorp made the decision to proceed with the portions of the project required for reliability and customer needs. PacifiCorp informed the Nevada Public Utility Commission in January 2011 that the Mona to Crystal segment would be postponed indefinitely.

Segment H – Hemingway to Captain Jack

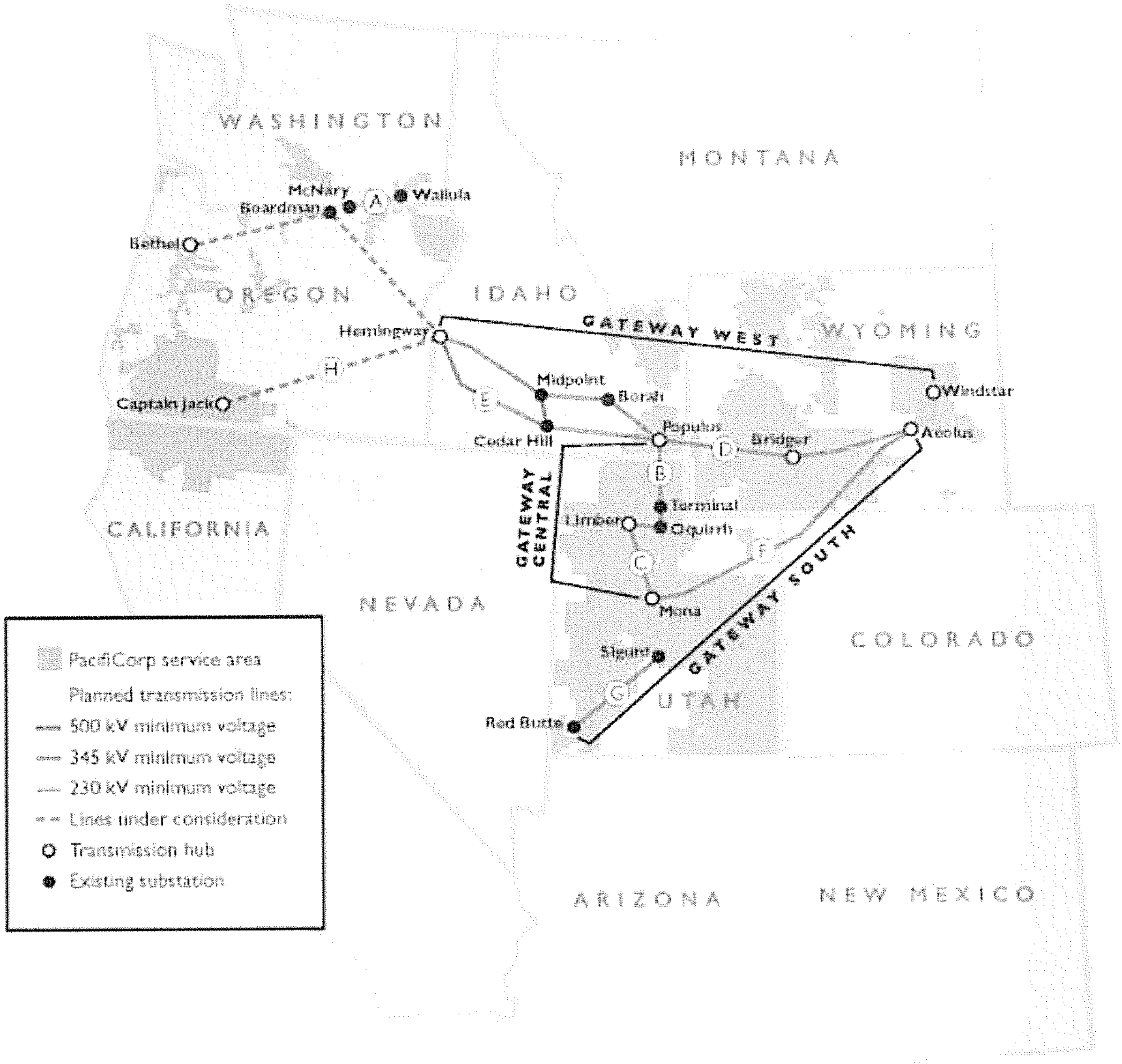


The Hemingway to Captain Jack project was planned as part of the Energy Gateway transmission investment to significantly improve the connection between PacifiCorp's east and west control areas and to help deliver more diverse energy resources to serve PacifiCorp's Oregon, Washington and California customers.

As planned, the project would be a single circuit 500 kV line running approximately 375 miles between the Hemingway substation south of Boise, Idaho, and the Captain Jack substation near Klamath Falls, Oregon. This project and other proposed lines in the area have been reviewed as part of the Western Electricity Coordinating Council regional planning process.

As part of its ongoing review of the Hemingway to Captain Jack project, PacifiCorp has considered the prudence of this project in light of other proposed lines, including the Boardman to Hemingway line initiated by Idaho Power Company (IPC) and Portland General Electric's (PGE) proposed Cascade Crossing transmission line between Boardman and the Salem, Oregon area. Recognizing the potential mutual benefits and value for customers of jointly developing transmission, PacifiCorp has entered into Memorandums of Understanding with IPC and PGE to explore potential partnership opportunities for the proposed Hemingway to Boardman and Cascade Crossing transmission projects. Should the customer and system benefits of these potential partnerships exceed those of PacifiCorp's proposed Hemingway to Captain Jack project, the Company will pursue these joint development opportunities in place of Hemingway to Captain Jack.

Figure 10.1 –Energy Gateway Transmission Expansion Plan



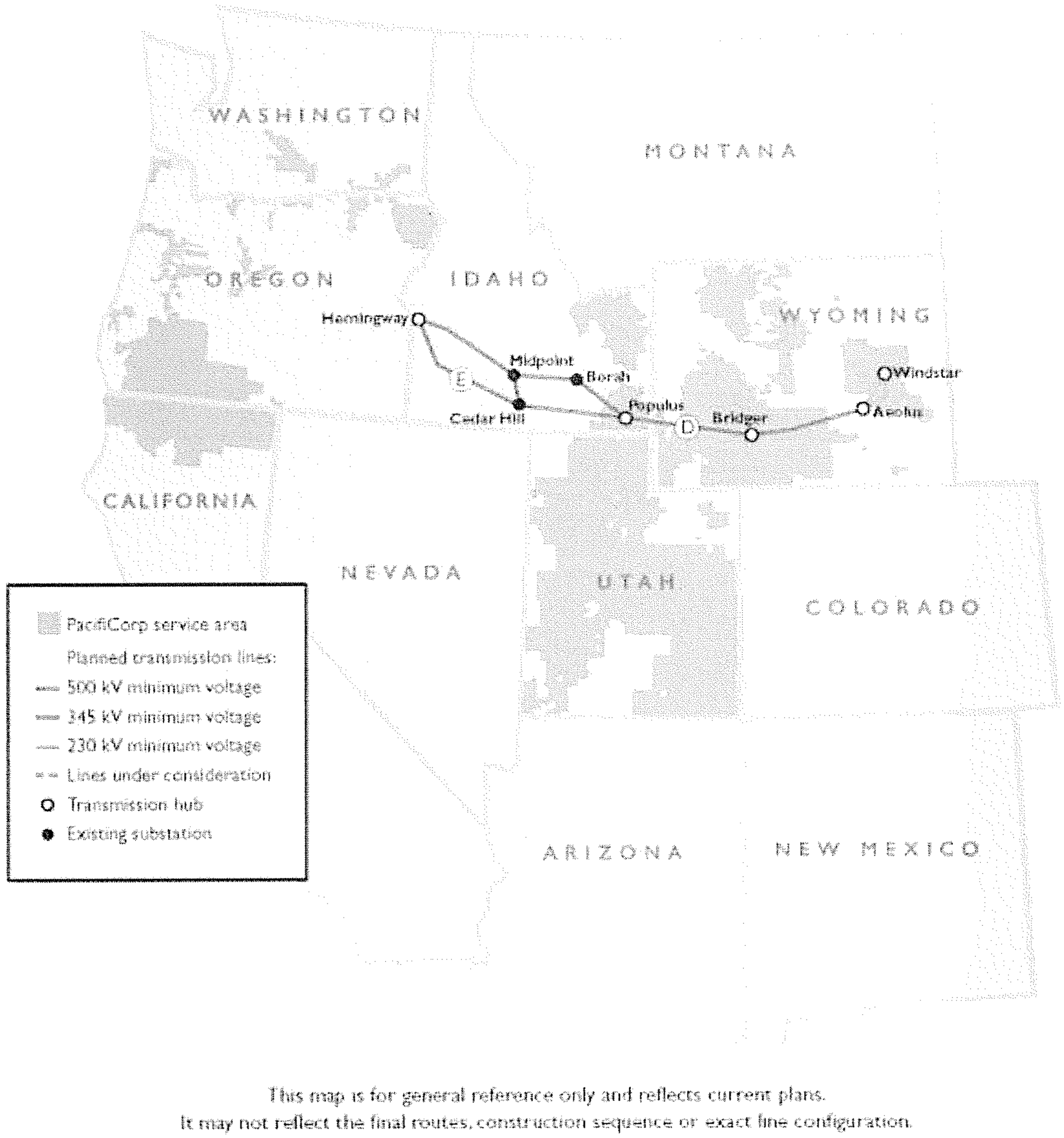
This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

Figure 10.2 – 2012-2014 Energy Gateway Additions for Acknowledgement

Segment	Description	Planned in-service	Incremental capacity upon segment completion	Incremental capacity upon completion of future Gateway segments
(A) Wallula to McNary	230 kV, single circuit	2012-2013	400 MW (bi)	400 MW (bi)
(C) Mona to Limber Limber to Oquirrh Oquirrh to Terminal	500 kV, single circuit 345 kV, double circuit 345 kV, double circuit	2013 2013 2014	700 MW (bi)	1,000 MW (bi)
(G) Sigurd to Red Butte	345 kV, single circuit	2014	550 MW (s-n) 400 MW (n-s)	550 MW (s-n) 400 MW (n-s)

(bi) = bi-directional; (n-s) = north-to-south; (s-n) = south-to-north; (e-w) = east-to-west; (w-e) = west-to-east

Figure 10.3 – 2015-2018 Energy Gateway Additions for Information Only

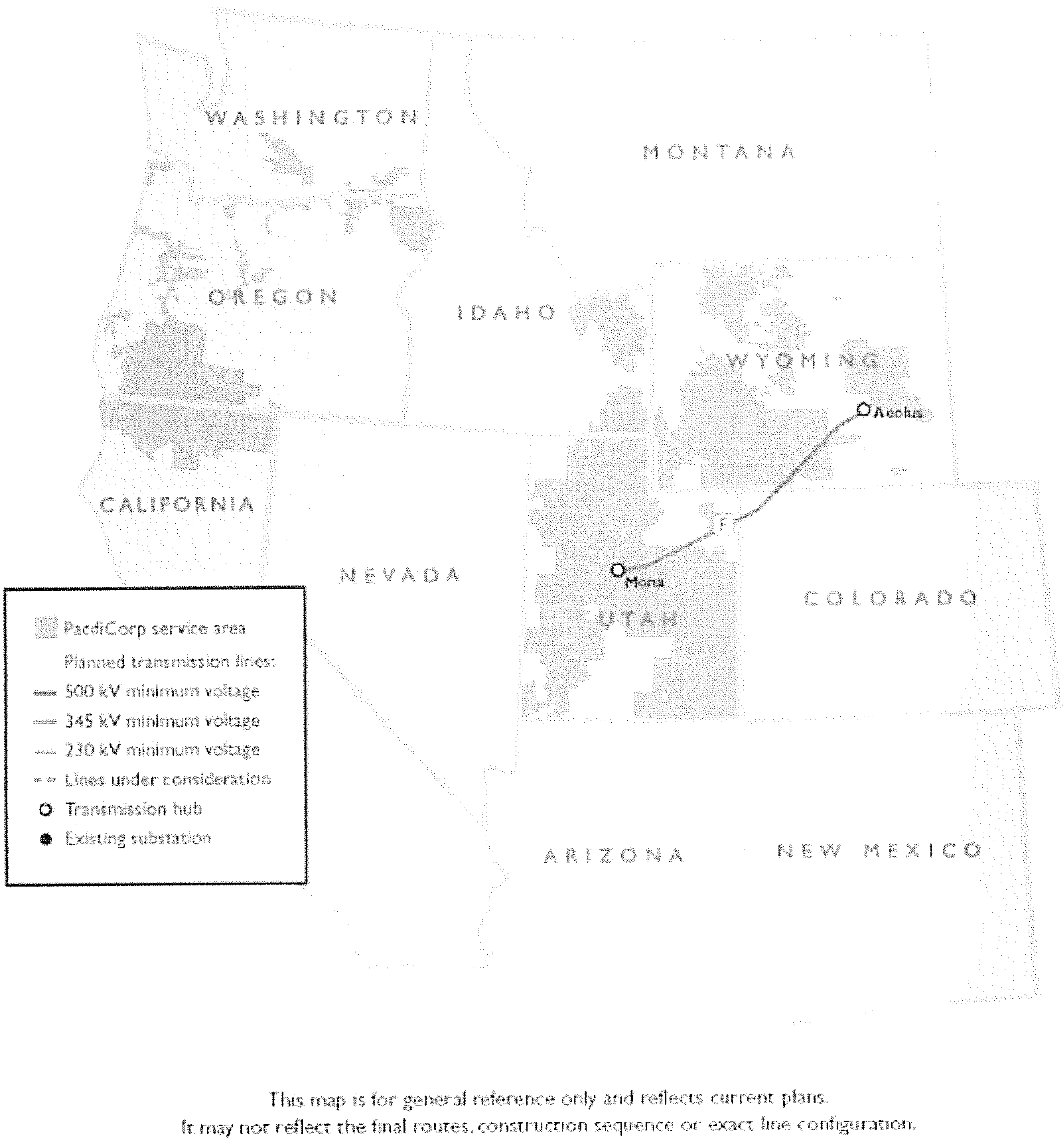


Segment	Description	Planned in-service	Incremental capacity upon segment completion	Incremental capacity upon completion of future Gateway segments
(D) Windstar to Aeolus Aeolus to Populus	2-230 kV, single circuit[79] 500 kV, single circuit	2015-2017	700 MW (e-w) 700 MW (bi)	1,200 MW (e-w) 1,500 MW (bi)
(E) Populus to Hemingway	500 kV, single circuit	2015-2018	600 MW (e-w) 800 MW (w-e)	600 MW (e-w) 800 MW (w-e)

(bi) = bi-directional; (n-s) = north-to-south; (s-n) = south-to-north; (e-w) = east-to-west; (w-e) = west-to-east

[79] Plus rebuild of existing Windstar to Aeolus 230 kV line

Figure 10.4 – 2017-2019 Energy Gateway Additions for Information Only



Segment	Description	Planned in-service	Incremental capacity upon segment completion	Incremental capacity upon completion of future Gateway segments
(F) Aeolus to Mona	500 kV, single circuit	2017-2019	1,500 MW (bi)	1,500 MW (bi)

(bi) = bi-directional; (n-s) = north-to-south; (s-n) = south-to-north; (e-w) = east-to-west; (w-e) = west-to-east