

Assuring a **bright**
future for our customers



2007

Integrated Resource Plan

Appendices



Pacific Power | Rocky Mountain Power | PacifiCorp Energy

This 2007 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.

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Cover Photos (Left to Right):

Wind: Foot Creek 1

Hydroelectric Generation: Yale Reservoir (Washington)

Demand side management: Agricultural Irrigation

Thermal-Gas: Currant Creek Power Plant

Transmission: South Central Wyoming line

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APPENDIX A – BASE ASSUMPTIONS

This appendix will cover the base assumptions used for both the Capacity Expansion Module and the Planning and Risk model used for portfolio analysis in the 2007 Integrated Resource Plan.

GENERAL ASSUMPTIONS

Study Period

PacifiCorp currently uses a calendar year that begins on January 1 and ends December 31. The study period covers a 20-year period beginning January 1, 2007 through December 31, 2026.

Inflation Curve

Where price forecasts and associated escalation rates were not established by external sources, IRP simulations and price forecasts were performed with PacifiCorp’s inflation rate schedule (See Table A.1 below). Unless otherwise stated, prices or values in this appendix are expressed in nominal dollars.

Table A.1 – Inflation

Calendar Years	Average Annual Rate (%)
2007-2013	1.86
2014-2020	1.80
2021-2026	1.88

Planning Reserve Margin

PacifiCorp assumed both 12 and 15 percent planning margin for developing the load and resource balance. Capacity Expansion Module scenario analysis used 12 percent as the low case, 15 percent as the medium case and 18 percent as a high case during the initial phase of analyses. To preserve planning flexibility, the company adopted a reserve margin range of 12 to 15 percent in recognition of uncertainties concerning the cost and reliability impact of evolving state resource policies to foster renewable energy development and reduce utilities’ carbon footprints.

LOAD FORECAST

This load forecast section provides state-level forecasted retail sales summaries, load forecasting methodologies, and the elasticity studies. Chapter 4 provides the forecast information for each state and the system as a whole by year for 2007 through 2016.

State Summaries

Oregon

Table A.2 summarizes Oregon state forecasted sales growth compared with historical growth by customer class.

Table A.2 – Historical and Forecasted Sales Growth in Oregon

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	5,374	4,614	2,957	211	50	13,207
2006 GWh	5,554	4,843	3,238	237	41	13,912
Average Annual Growth Rate						
1995-05	1.2%	2.0%	-3.5%	-3.1%	5.0%	0.1%
2007-16	0.7%	1.5%	-0.9%	0.0%	0.9%	0.6%

The forecast of residential sales is expected to have a slightly slower growth than has been experienced historically. Population growth is expected to continue in the service area, which is driving some of the growth, while usage per customer in the residential class is expected to decline slightly due to conservation.

Forecasted commercial class sales are projected to grow slightly more slowly over the forecast horizon compared to historical periods. Usage per customer is projected to remain flat due to increased equipment efficiency which offsets increased saturation of air conditioning.

Forecasted industrial class sales are projected to decline more slowly over the forecast horizon compared to historical periods. In the later years of this historical period, two large industrial customers chose to leave PacifiCorp's system. This, coupled with declines over the decade in the lumber and wood products industries, resulted in an overall decline in sales to this class. Over the forecast horizon, continuing growth is expected in food processing industries, specialty metals manufacturing industries, and niche lumber and wood businesses, along with continued diversification in the manufacturing base in the state.

The factors influencing the forecasted sales growth rates are also influencing the forecasted peak demand growth rates.

Washington

Table A.3 summarizes Washington state forecasted sales growth compared with historical growth by customer class.

Table A.3 – Historical and Forecasted Sales Growth in Washington

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	1,587	1,417	1,054	175	11	4,244
2006 GWh	1,596	1,415	990	155	10	4,166
Average Annual Growth Rate						
1995-05	1.1%	2.1%	0.8%	3.1%	2.9%	1.4%
2007-16	1.1%	1.2%	2.0%	0.0%	0.1%	1.3%

The growth in residential class sales is due to continuing population growth and household formation in this part of PacifiCorp's service area. Usage per customer is expected to increase slightly due to increases in both real income and the residential square footage.

The continuing residential customer growth also affects the commercial sector through increasing numbers of commercial customers. Usage per commercial customer is decreasing during the forecast horizon due to increasing saturations in air-conditioning and office equipment that are being offset by efficiency gains in other end-uses, such as lighting.

The industrial class is projected to grow at rates above the historical rate. Industrial production is projected to continue to grow in the food, lumber, and paper industries in the state. There are indications that bio-diesel facilities will locate in the state during the forecast period.

California

Table A.4 summarizes California state forecasted sales growth compared with historical growth by customer class.

Table A.4 – Historical and Forecasted Sales Growth in California

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	391	290	64	89	2	837
2006 GWh	398	293	62	96	2	851
Average Annual Growth Rate						
1995-05	1.0%	2.4%	-2.0%	2.0%	0.4%	1.3%
2007-16	0.9%	1.8%	-0.4%	0.0%	0.1%	1.1%

The rate of growth in residential class sales is driven, in part, by the continuing growth in population in this part of PacifiCorp's service area. Usage per customer in the residential class is declining slightly. Home sizes continue to increase, resulting in more growth in use per customer but this is more than offset by the increasing adoption of efficient appliances. In addition, summer electrical usage increases from air conditioning additions are being somewhat offset by declining electric spacing heating saturations and appliance efficiency gains.

The continuing population growth also affects sales in the commercial sector through continued commercial customer growth. Additionally, commercial usage per customer is increasing due to greater square footage per building in new construction, increases in the number of offices, and the increasing use of office equipment in all commercial structures. However, some of this growth is being offset from increased equipment efficiency over the forecast horizon.

Declines over the decade in the lumber and wood product industries production resulted in an overall decline in the industrial sales; however, there are indications that this trend has ended and growth in other businesses are expected to continue.

Utah

Table A.5 summarizes Utah state forecasted sales growth compared with historical growth by customer class.

Table A.5 – Historical and Forecasted Sales Growth in Utah

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	5,707	6,776	6,944	151	547	20,124
2006 GWh	6,139	7,079	7,312	171	525	21,227

	Residential	Commercial	Industrial	Irrigation	Other	Total
Average Annual Growth Rate						
1995-05	4.2%	5.0%	0.9%	2.9%	0.3%	3.0%
2007-16	3.4%	3.3%	1.7%	0.7%	0.3%	2.7%

Utah continues to see natural population growth that is faster than many of the surrounding states. During the historical period, Utah experienced rapid population growth with a high rate of in-migration. However, the rate of population growth is expected to be lower in the coming decade as in-migration into the state slows. Use per customer in the residential class should continue at current levels for the forecast horizon. One of the reasons for the high usage per customer is that newer homes are assumed to be larger. In addition, it is assumed that air conditioning saturation rates for single family and manufactured houses will continue to grow.

The relatively high population growth also affects sales in the commercial sector by continued commercial customer growth. Usage per customer is projected to increase with new construction having greater square footage per building and increasing usage of office equipment. However, some of this growth is being offset from equipment efficiency gains over the forecast horizon.

The industrial class has been experiencing significant industrial diversification in the state and will continue to cause sales growth in the sector. Utah has a strategic location in the western half of the United States, which provides easy access into many regional markets. The industrial base has become more linked to the region and is less dependent on the natural resource base within the state. This provides a strong foundation for continued growth into the future.

The peak demand for the state of Utah is expected to have a high growth rate during the forecast period. This is due to several factors: first, newer residential structures are assumed to be larger; second, the air conditioning saturation rates in the state continue to increase in the residential and commercial sectors; and third, newly constructed commercial structures are assumed to be larger than during historical periods.

Idaho

Table A.6 summarizes Idaho state forecasted sales growth compared with historical growth by customer class.

Table A.6 – Historical and Forecasted Sales Growth in Idaho

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	652	382	1,650	534	2	3,221
2006 GWh	678	401	1,659	592	2	3,332
Average Annual Growth Rate						
1995-05	1.7%	5.6%	-0.0%	2.5%	3.2%	1.3%
2007-16	2.2%	3.1%	0.0%	0.6%	1.2%	1.0%

The growth of sales in the residential sales class continues to be strong in the forecast horizon due to customer growth and increased usage per customer. The customer growth is driven by strong net in-migration and household formation. The increased usage per customer is driven by

larger home size and a relatively large number of people per household. It is also assumed that air conditioning saturation rates will continue to be increasing during the forecast horizon.

The growth rate for commercial class sales is expected to be less than historic levels but will continue to be strong due to customer growth in response to the increasing residential customer growth and due to an increase in the number of offices. Usage per customer is projected to increase, which has been influenced in part by new construction at the Brigham Young University Idaho campus, increased air conditioning saturation, office equipment, and exterior lighting. However, this growth is somewhat offset by equipment efficiency gains over the forecast horizon.

Industrial sales are assumed to be near maximum levels of production and remain there during the forecast horizon.

Wyoming

Table A.7 summarizes Wyoming state forecasted sales growth compared with historical growth by customer class.

Table A.7 – Historical and Forecasted Sales Growth in Wyoming

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	939	1,290	5,756	16	13	8,013
2006 GWh	970	1,367	5,939	21	13	8,309
Average Annual Growth Rate						
1995-05	1.4%	2.5%	1.2%	4.1%	0.1%	1.4%
2007-16	1.6%	2.6%	6.7%	-0.5%	0.2%	5.6%

The residential sales forecast is expected to continue to grow at nearly historical rates. Population growth is expected to continue in the service area, which causes some of the growth. Home sizes continue to increase, resulting in increased general use per customer. Increasing air conditioning saturations are resulting in more use per customer during the summer months.

Commercial sales are projected to grow at a similar rate over the forecast horizon compared to historical periods due to customer growth and increasing usage per customer. Customer growth occurs in response to residential customer growth and the growth of the office sector. Usage per customer is projected to increase for the forecast period due to increases of office and miscellaneous equipment.

A major change in the Wyoming sales forecast occurs in the industrial sales sector. Large gas extraction customers are expected to locate in the PacifiCorp service area. The location of these industrial customers in the service area also contributes to the growth in the residential and commercial customer sectors.

Class 2 DSM

Identified and budgeted Class 2 DSM programs have been included in the load forecast as a decrement to the load. By 2016, there are 143 MWa of Class 2 programs in the forecast. This savings includes 10 MWa to be implemented by the Energy Trust of Oregon within PacifiCorp's service territory. Table A.8 shows average program savings and peak obligation hour savings by

year. In 2016, these Class 2 programs reduce peak system load from what it otherwise would have been by 2.2%.

Table A.8 – Class 2 DSM Included in the System Load Forecast

MW _a	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
PacifiCorp	19	38	54	62	75	87	100	112	124	135
Energy Trust of Oregon (ETO)	11	20	27	36	45	54	63	73	82	92
TOTAL	30	58	81	98	120	141	163	185	206	227
Peak Reduction (MW)	40	77	108	131	160	188	217	247	275	303

Near Term Customer Class Sales Forecast Methods

Residential, Commercial, Public Street and Highway Lighting, and Irrigation Customers

Sales to residential, commercial, public street and highway lighting, and irrigation customers are developed by forecasting both the number of customers and the use per customer in each class. The forecast of kWh sales for each customer class is the product of two separate forecasts: number of customers and use per customer.

The forecast of the number of customers relies on weighted exponential smoothing statistical techniques formulated on a twelve-month moving average of the historical number of customers. For each customer class the dependent variable is the twelve-month moving average of customers. The exponential smoothing equation for each case is in the following form:

$$S_t = w * x_t + (1-w) * S_{t-1}$$

$$S_t^{(2)} = S_t * x_t + (1-w) * S_{t-1}^{(2)}$$

$$S_t^{(3)} = S_t^{(2)} * x_t + (1-w) * S_{t-1}^{(3)}$$

where x_t is the twelve-month moving average of customers. The form of this forecasting equation is known as a triple-exponential smoothing forecast model and, as derived from these equations, most of the weight is applied to the more recent historical observations. By applying additional weight to more current data and utilizing exponential smoothing, the transition from actual data to forecast periods is as smooth as possible. This technique also ensures that the December to January change from year to year is reflective of the same linear pattern. These forecasts are produced at the class level for each of the states in which PacifiCorp has retail service territory. PacifiCorp believes that the recent past is most reflective of the near future. Using weights applies greater importance to the recent historical periods than the more distant historical periods and improves the reliability of the final forecast.

The average use per customer for these classes is calculated using regression analysis on the historical average use per customer, which determines if there is any material change in the trend over time. The regression equation is of the form,

$$KPC_t = a + b*t$$

where KPC is the annual kilowatt-hours per customer and “t” is a time trend variable having a value of zero in 1992 with increasing increments of one thereafter. “a” and “b” are the estimated intercept and slope coefficients, respectively, for the particular customer class. As in the forecast of number of customers, the forecasts of kilowatt-hours per customer are reviewed for reasonableness and adjusted if needed. The forecast of the number of customers is multiplied by the forecast of the average use per customer to produce annual forecasts of energy sales for each of the four classes of service.

Industrial Sales and Other Sales to Public Authorities

These classes are diverse. In the industrial class, there is no typical customer. Large customers have differing usage patterns and sizes. It is not unusual for the entire class to be strongly influenced by the behavior of one customer or a small group of customers. In order to forecast customer loads for industrial and other sales to public authorities, these customers are first classified based on their Standard Industrial Classification (SIC) codes, which are numerical codes that represent different types of businesses. Customers are further separated into large electricity users and smaller electricity users. PacifiCorp’s forecasting staff, which consults with each PacifiCorp customer account manager assigned to each of the large electricity users, makes estimates of that customer’s projected energy consumption. The account managers maintain direct contact with the large customers and are therefore in the best position to know whether any plans or changes in their business processes may impact their energy consumption. In addition, the forecasting staff reviews industry trends and monitors the activities of the customers in SIC code groupings that account for the bulk of the industry sales. The forecasting staff then develops sales forecasts for each SIC code group and aggregates them to produce a forecast for each class.

Long Term Customer Class Sales Forecast Methods

Economic and demographic assumptions are key factors influencing the forecasts of electricity sales. Absent other changes, demand for electricity will parallel other regional and national economic activities. However, several influences can change that parallel relationship; for example, changes in the price of electricity, the price and availability of competing fuels, changes in the composition of economic activity, the level of conservation, and the replacement rates for buildings and energy-using appliances. The long-term forecast considers all of these as variables. The following is a generalized discussion of the methodology implemented for the long-term forecast. The forecast is derived from a consistent set of economic, demographic and price projections specific to each of the six states served by PacifiCorp. Forecasts of employment, population and income with a consistent view of the western half of the United States are used as inputs to the forecasting models.

Economic and Demographic Sector

Employment serves as the major determinant of future trends among the economic and demographic variables used to “drive” the long-term sales forecasting equations. PacifiCorp’s meth-

odology assumes that the local economy is comprised of two distinct sectors: basic and non-basic, as presented in “regional export base theory.”¹

The basic sector is comprised of those industries that are involved in the production of goods destined for sales outside the local area and whose market demand is primarily determined at the national level. PacifiCorp calculates a region’s share of the employment for these specific industries based on national forecasts of employment for the industries.

The non-basic sector theoretically represents those businesses whose output serves the local market and whose market demand is determined by the basic employment and output in the local economy.

This simplistic definition of industries as basic or non-basic does not directly confront the problem that much commercial employment (traditionally treated as non-basic) has assumed a more basic nature. This problem is overcome by including other appropriate additional national variables, such as real gross national product in the modeling. In addition, forecasts for county and state populations are also employed as forecast drivers. From these, service territory level population forecasts are developed and used.

Two primary measures of income are used in producing the forecast of total electricity sales. Total personal income is used as a measure of economic vitality which impacts energy utilization in the commercial sector. Real per capita income is used as a measure of purchasing power which impacts energy choice in the residential sector. PacifiCorp’s forecasting system projects total personal income on a service territory basis.

Residential Sector

For the first time PacifiCorp implemented the end-use software package Residential End-Use Energy Planning System (REEPS) to produce the long-term residential sales forecast. This residential end-use forecasting model has been developed to forecast specific uses of electricity in the customer’s home. The model explicitly considers factors such as persons per household, fuel prices, per capita income, housing structure types, and other variables that influence residential customer demand for electricity. Residential energy usage is projected on the basis of 14 end-uses. These uses are space heating, water heating, electric ranges, dishwashers, electric dryers, first refrigerators, second refrigerators, lighting, air conditioning, freezers, microwave ovens, electric clothes washers, color televisions and residual uses. Air conditioning can be either central, window or evaporative (swamp coolers).

For each end-use and structure type, PacifiCorp looks first at saturation levels (the number of customers equipped for that end-use) and how they may change in response to demographic and economic changes. PacifiCorp then looks at penetration levels (how many households are expected to adopt that end-use in the future), given the economic and demographic assumptions. In addition, the number of houses that currently have the end-use will be removed upon demolition of the structure. Some appliances may be replaced several times before a home is removed. The

¹ The regional export base theory contends that regional economies are dependent on industries that export outside of the region. These industries, and the ones that support them, are the industries that are the major job creators of the region.

life expectancy of various appliances compared to the life expectancy of a home is considered in the forecasting process. It is also possible that for a particular appliance more than one exists within a household. For certain appliances, such as air conditioning, the saturation rate has been adjusted to account for this occurrence. For other appliances, such as lighting, the saturation rate is assumed to be one, and the usage per appliance for the average household is adjusted to account for more than one light fixture in the house. In this case the average usage per appliance represents the lighting electrical usage in the average household.

The basic structure of the end-use model is to multiply the forecast appliance saturation by the appropriate housing stock, which is then multiplied by the annual average electricity use per appliance.

Consumption= Housing Stock k , X Saturation of Appliance ik X Electricity Usage of Appliance ik

where: i = appliance type
 k =housing type

Annual average electricity use per appliance for each structure type is either estimated by using a conditional demand analysis or it is based upon generally accepted institutional, industry and engineering standards.

Within REEPS, PacifiCorp models three structure types within two age categories, new and existing, because consumption patterns vary with dwelling type as well as with age. Therefore new and existing homes are separated further into single family, multi-family and manufactured home dwelling types.

REEPS allows PacifiCorp to calculate the number of residential customers within each of the new and existing customer categories. These customers are then distributed between the various structure types and sizes. End uses are forecasted for each structure and customer category and these are multiplied by the annual consumption level for each end use. Summing the results gives the total residential sales.

Commercial Sector

For the first time PacifiCorp implemented the end-use software package Commercial End-Use Energy Planning System (COMMEND) to produce the long-term commercial sales forecast. It forecasts electricity in the same fashion as the REEPS model but uses energy use per square foot for ten end-uses among ten commercial building types.

Consumption= Square foot k , X Saturation of Appliance ik X Electricity Usage of Appliance ik

where: i = Appliance Type
 k = Commercial Activity Type

The nine end-uses are space heating, water heating, space cooling, ventilation, refrigeration, interior lighting, exterior lighting, cooking, office equipment and miscellaneous uses.

Ten building types are modeled: offices, restaurants, retail, grocery stores, warehouses, colleges, schools, health, lodging, and miscellaneous buildings. Individual forecasts for each building type are totaled for an overall commercial sector forecast.

Industrial Sector

PacifiCorp's industrial sector is somewhat dominated by a small number of firms or industries. The heterogeneous mix of customers and industries, combined with their widely divergent characteristics of electricity consumption indicates that a substantial amount of disaggregation is required when developing a proper forecasting model for this sector. Accordingly, the industrial sector has been heavily disaggregated within the manufacturing and mining customer segments.

The manufacturing sector is broken down into ten categories based on the Standard Industrial Classification code system. These are: food processing (SIC 20), lumber and wood products (SIC 24), paper and allied products (SIC 26), chemicals and allied products (SIC 28), petroleum refining (SIC 29), stone, clay and glass (SIC 32), primary metals (SIC 33), electrical machinery (SIC 36) and transportation equipment (SIC 37). A residual manufacturing category, composed of all remaining manufacturing SIC codes, is also forecasted.

The mining industry, located primarily in Wyoming and Utah, has been disaggregated into at least four categories. Separate forecast are performed for the following industries: metal mining (SIC 10), coal mining (SIC 12), oil and natural gas exploration, pumping and transportation (SIC 13), non-metallic mineral mining (SIC 14); there also exists an "other" mining category in some states.

The industrial sector is modeled using an econometric forecasting system.

Other Sales

The other sectors to which electricity sales are made are irrigation, street and highway lighting, interdepartmental and other sales to public authorities.

Electricity sales to these smaller customer categories are either forecasted using econometric equations or are held constant at their historic sales levels.

Merging of the Near-Term and Long-Term Sales Forecasts

The near-term forecast has a horizon of at most three years while the long-term forecast has a horizon of approximately twenty years. Each forecast uses different methodologies, which model the influential conditions for that time horizon. When the forecast of usage for a customer class differs between the near-term and the long-term, judgments and mathematical techniques are implemented in the last year of the near-term forecast which converges these values to the long-term forecast.

Total Load Forecasting Methods

System Load Forecasts

The sales forecasts by customer class previously discussed measure sales at the customer meter. In order to measure the total projected load that PacifiCorp is obligated to serve, line losses must be added to the sales forecast. The state sales forecasts are increased by estimates for system line

losses. Line loss percentages vary by type of service and represent the additional electricity requirements to move the electricity from the generating plant to each end-use customer. This increase creates the total system load forecast on an annual basis. This annual forecast is further distributed to an hourly load forecast so that the peak hour demand forecast is determined.

Hourly Load Forecasts

To distribute the loads across time, PacifiCorp has developed a regression based tool that models historical hourly load against several independent variables at the state level. These models have a large number of independent variables. Many of these represent spatial conditions over the year, such as the time of day, the week of the year or day of the week. Additionally, the model uses hourly temperatures for weather stations where the bulk of the load in the state resides. A variable representing the humidity levels in the state is also used.

Forecasts of the many independent variables are used with these models to create forecasts of hourly loads relative to the many different factors. For the spatial variables, the date and time in the future is used. Typically, the load on a weekend is lower than on a weekday because industrial and some commercial customers use less electricity. Therefore, a variable used to identify a weekend would have a lower contribution to the forecasted load than a weekday variable; using the calendar date for a future period identifies these spatial conditions. For the weather values, the models use the equivalent of the 30-year average temperature for the weather stations at the appropriate day and time in the future. This is also what is used for the humidity measure.

A review of the forecasted growth of the hourly load over time against historical growth rates is made to ensure that the loads are growing at the appropriate times. State loads are aggregated by month and by time of day, and future growth rates are compared with historical growth rates. This allows PacifiCorp to review the nighttime growth rates versus daytime growth rates. Growth in the winter months may differ from the growth in the spring and fall. All of this is reviewed and trends are incorporated to reflect the historical patterns observed. Hourly loads are then totaled across the months of the forecast period to develop monthly loads. This process incorporates expected weather conditions into the appropriate month based on normal weather patterns.

System Peak Forecasts

The system peaks are the maximum load required on the system in any hourly period. Forecasts of the system peak for each month are prepared based on the load forecast produced using the methodologies described above. From these hourly forecasted values, forecast peaks for the maximum usage on the entire system during each month (the coincidental system peak) and the maximum usage within each state during each month are extracted.

Treatment of State Economic Development Policies

The load forecast for each state depends to some degree on the state economic forecast provided by Global Insights. The state economic forecast from Global Insights is dependent on a series of econometric equations based on historical values of state and national economic variables. To the extent that a state has had economic development policies in the past, it is reflected to a similar degree in the state economic forecast and, thus, impacts the load forecast. Periodically, Global Insights will include in the state economic forecast newly developed state economic policies judgmentally external to the econometric forecasting equations when it is deemed appropriate to

include such programs in the forecast. Since it is assumed that the economic forecast includes all existing and relevant new economic development programs, the load forecast includes the impacts of these programs.

Elasticity Studies

Since the 2004 IRP, PacifiCorp has performed three separate studies on the effects of the price of electricity on electricity usage in Utah. Each study evaluates the increasing block rates of the residential customer class. That is, the increasing price of electricity during the summer should cause a decline in the usage of electricity, especially during times of peak demand in Utah.

These three studies can be classified as

- 1) Total residential class analysis through econometric methods
- 2) Analysis, using econometric methods, of customers who called about their electric bills, and
- 3) Sub-group analysis of the residential class using cluster analysis and econometric analysis

Total Class Analysis

An econometric equation with usage per customer as the dependent variable and the real price of electricity, real household income, cooling degree days², heating degree days, real natural gas prices, and lagged use per customer as independent variables was developed. The time period of estimation was from 1982 through 2005. The results of this estimation indicate that the short-term price elasticity was -0.05 and that the long-term price elasticity was -0.09. Using either measure, it was determined that electricity is price inelastic, i.e., having an elasticity measure less than 1 in absolute value, or relatively unresponsive to changes in the price of electricity. In particular, the short-term elasticity measure indicates that for a 10 percent increase in price there is a 0.5 percent decline in the usage of electricity one year in the future. The long-term measure indicates that a 10 percent increase in the price of electricity ultimately leads to a 0.9 percent decline in electricity usage.

Analysis of Customers Who Called About Their Bills

During 2004 PacifiCorp received calls from 77 customers in Utah who indicated that they were calling about price issues. Of these 77 customers 13 had sufficient data to analyze their usage in response to price changes. An econometric equation was specified having the log of average monthly kilowatt-hours (kWh) as the dependent variable and the log of average real price current and lagged one month, the log of average usage per month lagged on month, heating degree days, and cooling degree days as independent variables.

The results of this econometric analysis indicated that the price variables were not statistically significant, which implies that the price coefficient and elasticity is statistically equal to zero. This result means that among those who notified PacifiCorp about changes in their price of electricity, there was no measurable change in their usage.

² All heating and cooling degree day variables in these analyses were based on temperature data from the Salt Lake City Airport.

Sub-group Analysis

The sub-group analysis used cluster analysis to group customer in accordance with their usage patterns over the last six years. To be included in the analysis, a customer had to be receiving service since July 1999 and the minimum amount of monthly usage was restricted to 55 kilowatt-hours.

The number of residential customers satisfying both conditions was 136,042. From this group of customers, the customers were clustered in accordance to their usage monthly usage patterns and amounts since July 1999. Using traditional cluster analysis techniques based on changes in monthly usage patterns and amounts, it was found that there were 23 clusters of 500 or more customers, with the final cluster being all other remaining customers. For these 24 groups of customers, regression analysis was performed with the dependent variable being the log of average monthly kilowatt-hours for the group and the independent variables being the log of the group average price per kilowatt-hours, the log of the group average price per kilowatt-hours and the log of the lagged average monthly kilowatt-hours, monthly heating degree days and monthly cooling degree days.

Of these 24 groups, two groups indicated a change in electricity usage in response to changes in the price of electricity. One group consisted of 1,490 customers with a summer average usage of 1,096 kilowatt-hours per month. This group had an elasticity measure of -2.51 which implies that a 10 percent increase in price would lead to a 25.1 percent decline in electricity usage for this group. The second group consisted of 505 customers with a summer average usage of 2,340 kilowatt-hours per month. This group had an elasticity measure of -0.95 which implies that a 10 percent increase in price would lead to a 9.5 percent decline in electricity usage for this group. These two groups represent roughly 2 percent of the 136,042 original customers. The remaining groups, which represented 98 percent of the customers, had no usage response to price changes. When weighing the groups according to their percent representation, the analysis implies that the total price elasticity is -0.036; i.e., electricity is price inelastic in total, which indicates that for the total residential class a 10 percent increase in price leads to a 0.36 percent decline in total residential usage.

COMMODITY PRICES

Market Fundamental Forecasts

PacifiCorp has historically relied on PIRA Energy's long range Reference Case forecast of natural gas prices as a primary input to its fundamental forward price curve. The PIRA forecast, translated to western delivery points, is used both to forecast electricity market prices in its fundamentals-based price forecasting model, Multi-objective Integrated Decision Analysis (MIDAS), and directly as fundamental forward price curves for natural gas.

PIRA Energy, through its Scenario Planning Service, also forecasts low and high scenarios for natural gas prices and estimates probabilities associated with these cases and the reference case. Prior to the August 2006 forward price curve, PacifiCorp did not use the low and high natural gas price scenarios in the development of its fundamental forward price curve, relying exclusively on the reference case.

Since 2003, when PIRA began its scenario planning service, natural gas prices and price forecasts have increased dramatically. A number of well documented supply and demand factors have contributed to this shift. In addition to a higher reference case, market changes have also led PIRA to forecast a wider range of low and high scenarios and higher probabilities associated with the high price scenarios.

In its August 2006 update to scenario forecasts, PIRA raised the probability associated with the high scenario from 25 to 30 percent and lowered the low scenario probability from 30 to 25 percent. PIRA documented these changes and the explanation for their forecast revisions in their quarterly update. The factors contributing to the shift include the following:

- Increasing probability of global liquefied natural gas (LNG) supply constraints and higher costs arising from slower expansion of liquefaction, escalation of project costs, rising global demand competition from emerging economies, higher political and supply disruption risks, and state gas companies' extraction of higher economic rents through royalties that have roughly doubled.
- Increasing risks to the timing and success of arctic frontier pipelines (Mackenzie Delta and Alaska North Slope).
- Mounting evidence of a more sensitive price elasticity of supply on the part of US producers who can rapidly step down exploration and production efforts in response to lower prices, especially in light of continuing high crude oil prices.

PIRA's ability to ascribe probabilities to their base, high and low cases will allow changes in any of the scenarios or probabilities associated with them to be reflected. PacifiCorp includes this improvement by probability-weighting PIRA's cases using PIRA's quarterly and annual updates to scenario forecasts. This method is an improvement over the company's historic use of the PIRA reference case forecast because it is responsive to increasing uncertainty surrounding future natural gas prices and also because it better reflects the current view of higher risk of higher natural gas prices in the future. Should the market outlook change and revert to one with more certainty and less high price risk, the probability weighted forecast will also capture that change.

PacifiCorp's official electricity price forecasts are a blend of market prices and output results from MIDAS.

Modeling Resource Additions in MIDAS

There are three general categories of resource additions added to the MIDAS price forecasting model: (1) renewable generation additions under renewable portfolio standard requirements or based on published integrated resource plans, (2) specifically identified new resource additions and (3) other capacity needed to meet load growth and planning reserve.

Multiple states in the Western Interconnection have adopted renewable portfolio standards. While renewable portfolio standards vary considerably by state, they all require affected entities to hit pre-specified renewable targets measured as a percentage of retail sales. If the mandated RPS targets in each state are to be met, various types of renewable resources must be added to the Western Interconnection resource supply over time.

Not all states and provinces within the Western Interconnection are subject to renewable portfolio standards. However, utilities within these regions have been including renewable generation in their integrated resource plans. The recent history of renewable additions confirms the likelihood of additions specified in integrated resource plans coming to fruition. MIDAS modeling includes this IRP-reflected trend of adding renewable resources in areas unaffected by renewable portfolio standard legislation in the Western Interconnection.

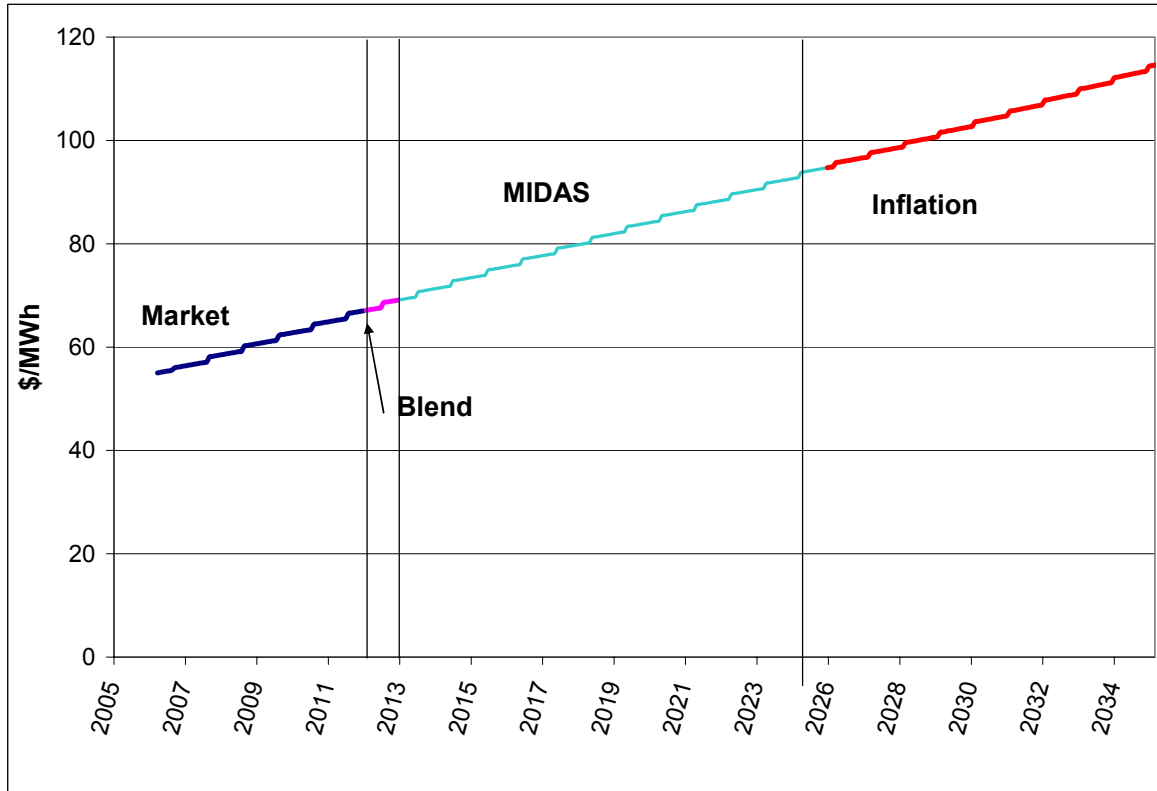
Total RPS-required and IRP-reflected renewable resource capacity additions added to MIDAS through 2025 is almost 20,000 GWh, which represents a mix of wind, geothermal, solar, biomass, landfill gas and small hydro projects.

New resource additions include specifically identified resource additions within the Western Interconnection and are only added to MIDAS after independent sources have verified that the units are under construction, operational or far enough into advanced development such that completion on-line date can be forecasted with confidence.

The MIDAS market resource expansion module adds new capacity in response to market prices or to meet load growth and planning reserves through its automated resource addition logic. Resources evaluated by MIDAS include natural gas simple cycle combustion turbines, intercooled aeroderivative simple cycles, and combined cycles (with and without duct firing); coal-fired units; and IGCC units. As regions express preferences for, or restrict the usage of, certain resource types (such as coal), the mix of resources that can be added by the model to meet load growth or planning reserves will change.

As Figure A.1 shows, market prices are used exclusively for the first 72 months. The official August 2006 prices reflected market prices on August 31, 2006. Market prices are derived from actual market transactions and broker quotes from polling the industry. Months 73-84 are the average of corresponding adjacent market and MIDAS prices (e.g. month 73 = (market month 61 + MIDAS month 85)/2). Starting in the 85th month and through 2025, prices from MIDAS are used exclusively. After 2025, prices are escalated using PacifiCorp's June 2006 inflation curve. The plot in Figure A.1 illustrates the blending period.

Figure A.1 – Natural Gas and Wholesale Electric Price Curve Components



For Illustration Purposes Only

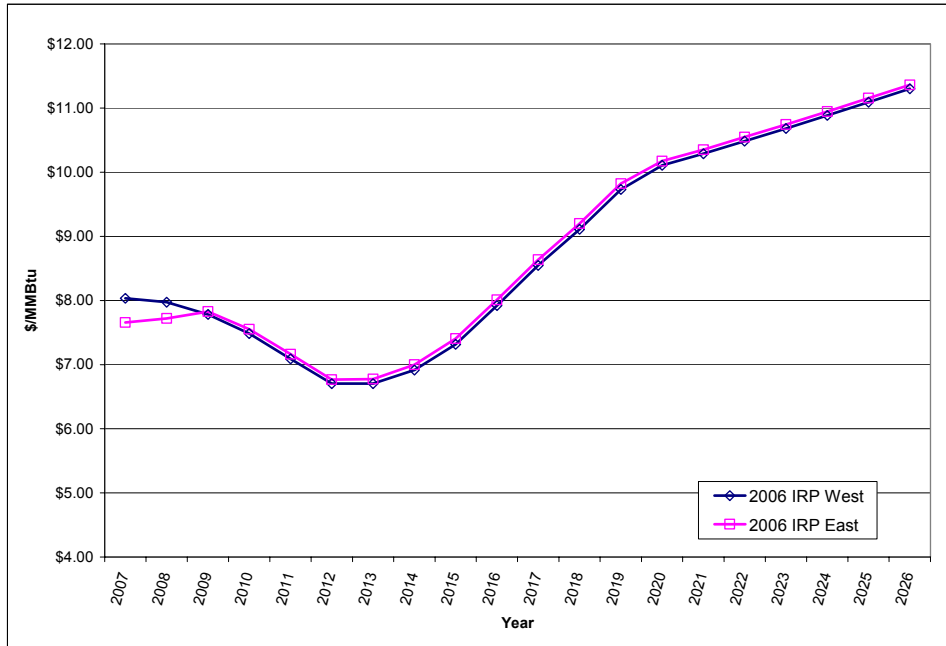
Gas Price Forecasts

As described in the Market Fundamental Forecast section, natural gas prices for the first six years are from the market on August 31, 2006 and for the next year are a blend of market prices and the gas prices used in MIDAS or PIRA. Starting in year seven, PIRA’s natural gas price forecast is used exclusively.

Natural gas price assumptions in MIDAS are based on PIRA Energy’s July 25, 2006 short-term forecast, the August 3, 2006 probabilistic weighted long-term gas forecast, and the August 22, 2006 long-term gas basis differentials. PIRA gas price projections are used in MIDAS through 2020. All prices are adjusted to be consistent with PacifiCorp’s official inflation curve issued in June 2006. Gas prices beyond 2020 are escalated using PacifiCorp’s inflation curve, which was updated on June 6, 2006.

IRP west side natural gas prices are an average of prices at the Sumas, Stanfield and Opal delivery points. Natural gas prices on the east side are based on the Opal delivery point prices. Figure A.2 shows the natural gas price forecasts used in the 2007 IRP.

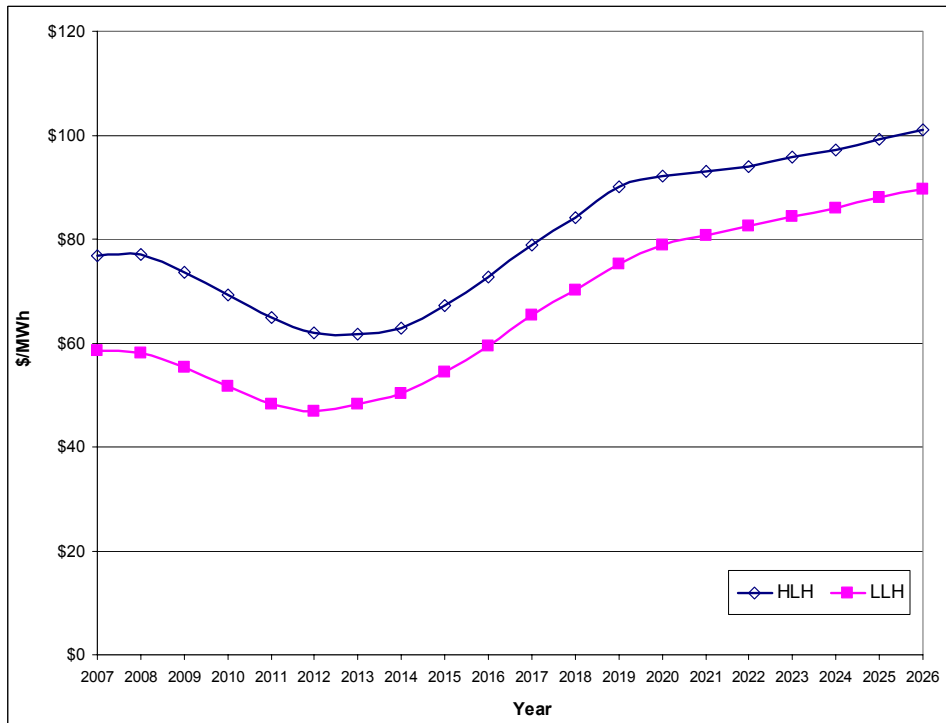
Figure A.2 – Natural Gas Price Curve



Wholesale Electricity Price Forecasts

Figure A.3 shows the annual average of heavy load hours (HLH) and light load hours (LLH) for wholesale electricity price forecasts dated August 31, 2006 that are used in the 2007 IRP.

Figure A.3 – Wholesale Electricity Price Forecast – Heavy Load Hours / Light Load Hours



Post-2020 real growth rate sensitivity analysis

At the May 10, 2005 public meeting, there was discussion about using real escalation for natural gas prices past 2020. PIRA provides natural gas prices through 2020 and PacifiCorp's official natural gas forecast beyond 2020 is escalated using PacifiCorp's inflation curve.

Another credible source, EIA Annual Energy Outlook February 2006, assumes gas escalation beyond 2020 to be approximately 1.5 percent in real terms.

This level of natural gas real escalation was run through the MIDAS model and market prices increased on average by 1.8 percent for the period 2012 through 2025. This was felt to be such a small impact that it was not required to run these market prices through the CEM and PaR models.

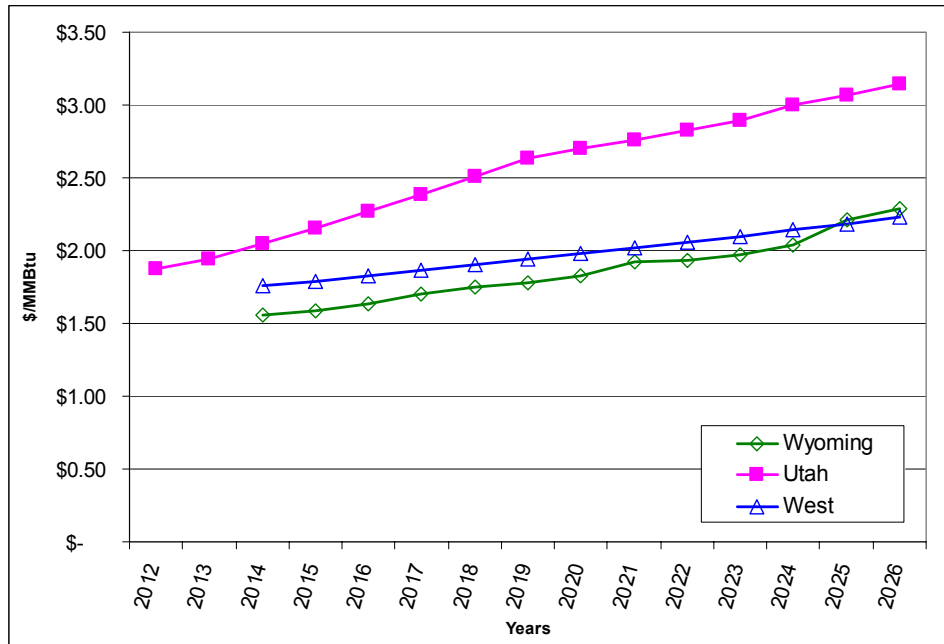
Regional transmission project impact analysis

For the regional transmission sensitivity, new transmission lines were added to the MIDAS model topology to determine market price sensitivity. A new 1,500 megawatts line was added from Wyoming to SP15 and a new 1,150 megawatts line was added from Utah to NP15. These lines were sized to be consistent with the size of new coal plants that were added in Wyoming and Utah by the MIDAS automatic resource addition logic. The average market prices for the period 2012 through 2025 decreased on average by approximately -0.2 percent. Gas generation is on the margin and determines market prices, which are relatively unaffected by increased transmission.

Coal Prices

Figure A.4 reflects PacifiCorp's estimate of delivered coal costs for its western control area (West), Wyoming and Utah. These costs figures are projections and remain sensitive to changes in overall supply and demand as well as changes in transportation costs.

Figure A.4 – Average Annual Coal Prices for Resource Additions



The current IRP plan only contemplates siting coal fired plants at PacifiCorp sites in the West, Wyoming, or Utah. PacifiCorp has not enclosed the costs of its generation fleet. Rather these costs are reflective of PacifiCorp's actual and projected contract costs rather than as a market indicator for future generating potential.

Coal Prices – West Side IGCC

The estimated delivered price of fuel delivered to west-side IGCC resources is \$1.50/MMBtu in calendar-year 2006 dollars. Published values for a 50/50 blend of petroleum coke and Powder River Basin (PRB) coal from a publicly available document on one of the proposed IGCC projects is estimated at \$1.35/MMBtu. The \$1.50/MMBtu value reflects uncertainty in the eventual delivered fuel cost, and is considered conservative based on discussions with one party currently proposing an IGCC facility.

It is expected that west-side IGCC resources will be able to be fueled with a wide range of fuels with the predominant fuel being low-cost petroleum coke or a blend of petroleum coke and low-cost western fuels, such as PRB coal. Recently proposed IGCC projects in the Pacific Northwest (Energy Northwest’s Pacific Mountain Energy Center and Summit Power Group’s Lower Columbia Clean Energy Center) are located adjacent to deep water ports with rail access allowing for multiple kinds of fuel to be delivered, including petroleum coke, as well as western and international coals. The range of coals that could be used will depend primarily on the design characteristics of the gasifier, the fuel processing equipment, and the capabilities of the syn-gas clean up systems.

EMISSION COSTS

Carbon Dioxide

The CO₂ adder is based upon the possibility of mandated green house gas reductions across the U.S. electric generating sector. The CO₂ adder reflects the company's estimate of compliance costs set at \$8/ton in 2008 dollars adjusted for inflation using PacifiCorp's official June 2006 inflation curve. To account for the uncertainty surrounding when such a cost will be imputed upon generating units, prices in 2010 and 2011 are probability weighted. The probability weighting applied to 2010 and 2011 prices are 0.5 and 0.75 respectively. By 2012, it is assumed that the CO₂ policy will be fully implemented. CO₂ prices are \$4.15/ton in 2010, \$6.34/ton in 2011 and \$8.62/ton in 2012 and escalate at PacifiCorp's June 2006 inflation curve.

The portfolio modeling utilized alternative CO₂ cost adders for scenario analysis. These alternative cost adders, along with the \$8/ton case, are shown in Table A.9.

Table A.9 – CO₂ cost adders used for Scenario Analysis

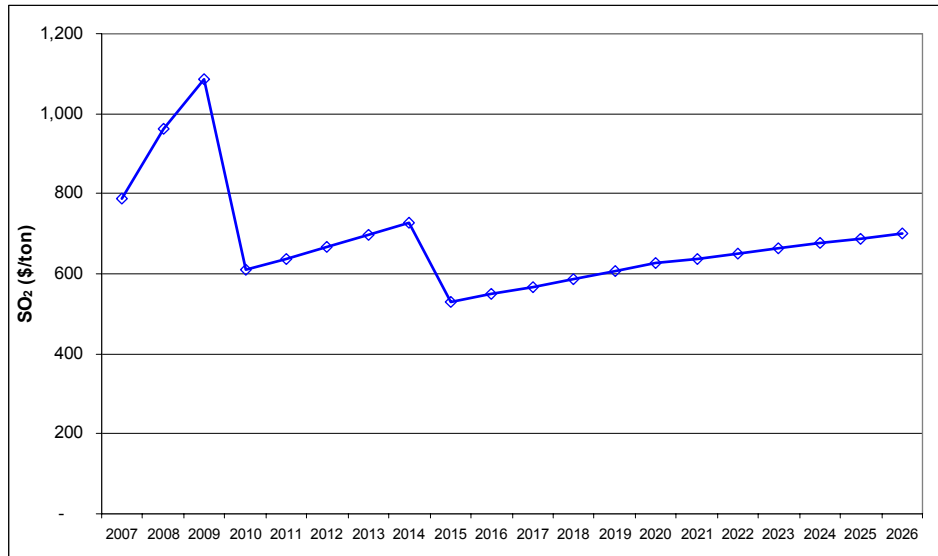
Year	CO ₂ Cost Adder Levels (\$/Ton, 2008 Dollars)				
	\$0	\$8	\$15	\$38	\$61
2010	0.00	4.15	4.15	4.15	4.15
2011	0.00	6.34	6.34	6.34	6.34
2012	0.00	8.62	8.62	8.62	8.62
2013	0.00	8.78	8.78	8.78	8.78
2014	0.00	8.94	11.05	17.69	24.34
2015	0.00	9.10	13.89	35.63	67.43
2016	0.00	9.26	17.64	44.09	70.55
2017	0.00	9.43	17.97	44.90	71.85
2018	0.00	9.60	18.29	45.71	73.15
2019	0.00	9.77	18.62	46.53	74.45
2020	0.00	9.95	18.96	47.38	75.82
2021	0.00	10.13	19.30	48.24	77.19
2022	0.00	10.32	19.67	49.14	78.64
2023	0.00	10.52	20.05	50.10	80.16
2024	0.00	10.72	20.43	51.05	81.68
2025	0.00	10.92	20.81	52.00	83.20
2026	0.00	11.13	21.20	52.99	84.78

Sulfur Dioxide

The short-term SO₂ allowance price forecast reflects PIRA's May 30, 2006 forecast. The SO₂ price trajectory is based upon the May 2006 Emissions Market Intelligence Service report issued by PIRA with the following adjustments. The PIRA price forecast is provided in real dollars and is adjusted for inflation using PacifiCorp's official inflation forecast issued in June 2006 to produce a nominal spot price forecast. Prices beyond 2020 are grown using the same official inflation curve. New SO₂ allowance prices were adopted to align with a PIRA update and EPA's

Clean Air Interstate Rule (CAIR). CAIR requires 2 existing Acid Rain Program allowances for each ton of emissions beginning in 2010 and 2.86:1 in 2015. This surrender ratio applies to Eastern states, but does not apply in the West. Effectively, this lowers allowance prices by a factor of 2 in 2010 and 2.83 in 2015. Figure A.5 shows the SO₂ spot emission costs used in the 2007 IRP.

Figure A.5 – Sulfur-Dioxide (SO₂) Spot Price Forecast



Nitrogen Oxides

The NO_x price forecast reflects PacifiCorp's expectation that by 2012 some form of annual NO_x cap-and-trade program will be imposed in the West. Considering the West does not have the same ground-level ozone problems experienced in the East, the forecast assumes that the NO_x trading program imposed in 2012 will be less stringent than what is currently targeted under EPA's Clean Air Interstate Rule (CAIR) for Eastern states. As a result, the marginal control technology is assumed to be selective non-catalytic reduction (SNCR) as opposed to selective catalytic reduction (SCR). While it is by no means certain that a market-based allowance trading mechanism will be imposed eventually on western states NO_x emissions, this assumption serves as a reasonable proxy for additional control costs that are likely to arise from NO_x regulations driven by existing regulations. In 2012 NO_x allowance costs are expected to be \$1,145/ton and escalate at PacifiCorp's June 2006 inflation curve.

Mercury

Mercury (Hg) prices reflect co-benefits from the installation of SO₂ and NO_x controls with a cap-and-trade program beginning in 2010. The mercury spot price forecast is based upon PIRA's Emissions Market Intelligence Service as of February 23, 2006. PIRA's forecast includes a range (high and low) for 2010, 2015, and 2020. Values between the years reported by PIRA are interpolated. All prices are adjusted to be consistent with PacifiCorp's official inflation curve issued in June 2006. Mercury prices are expected to be \$7,197/Lb in 2010.

RENEWABLE ASSUMPTIONS

Production Tax Credit

The production tax credit (PTC) incentive applies to new wind and geothermal plants with the intent of bringing their costs in line with other resource technologies such as resources fueled by coal and natural gas. In the 2007 IRP, the tax credit is incorporated into the wind supply curves. Although the current law applies only to wind projects brought on-line through 2007, the effect on supply curves was extended throughout the study horizon for the purposes of the IRP analysis. It is widely expected that the PTC deadline will be extended, and will only end at such a time as the cost of the technology declines to the point where tax credits are no longer needed to keep wind competitive with other resource types. The 2007 IRP does not contain any specific expectation regarding declining wind resource costs due to technology improvements, using the assumption of an extended PTC to cover the combination of PTC and technology improvement effects.

Renewable Energy Credits

Renewable energy credits (RECs), also known as green tags, are certificates that represent the reporting rights for a quantity of energy generated from a specific resource. Markets have developed around buying and selling RECs. Consumers desiring to encourage renewable resources may purchase RECs, sometimes matching all or a portion of their electric power usage. Utilities may also purchase RECs to satisfy minimum renewable energy requirements established in some states.

Since PacifiCorp's 2003 IRP, a value has been ascribed to the green tags generated by owned renewable energy projects. That value was estimated to be \$5 per megawatt-hour of generation for the first five years of production (constant nominal dollars). PacifiCorp called a number of green tag suppliers to ascertain whether the market value of RECs had substantially changed from where it has been over the past few years. Despite the expectation that increasing state minimum requirements for renewable generation would push market prices up, there was no clear indication that market prices had gone up. The potential market impacts of state standards was discussed, but the consensus was that the effect on market prices would be highly dependent on the specifics of state requirements, and did not clearly indicate a specific direction for green tag prices. In light of this, PacifiCorp has chosen to retain its REC value assumption of \$5 per megawatt-hour for five years in constant nominal dollars.

EXISTING RESOURCES

Hydroelectric Generation

Table A.10 provides an operational profile for each of PacifiCorp's hydroelectric generation facilities. The dates listed refer to a calendar year.

Table A.10 – Hydroelectric Generation Facilities

Plant	PacifiCorp Share (MW)	Location	License Expiration Date	Retirement Date
West				
Big Fork	4.15	Montana	2001	2051
Clearwater 1	15.00	Oregon	1997	2040
Clearwater 2	26.00	Oregon	1997	2040
Copco 1	20.00	California	2006	2046
Copco 2	27.00	California	2006	2046
East Side	3.20	Oregon	2006	2016
Fish Creek	11.00	Oregon	1997	2040
Iron Gate	18.00	California	2006	2046
JC Boyle	80.00	Oregon	2006	2046
Lemolo 1	29.00	Oregon	1997	2040
Lemolo 2	33.00	Oregon	1997	2040
Merwin	136.00	Washington	2009	2046
Rogue	46.76	Oregon	Various	Various
Slide Creek	18.00	Oregon	1997	2040
Soda Springs	11.00	Oregon	1997	2040
Swift 1	240.00	Washington	2006	2046
Toketee	42.50	Oregon	1997	2040
West Side	0.60	Oregon	2006	2016
Yale	134.00	Washington	2001	2046
Small West Hydro	21.01	CA/OR/WA	Various	Various
East				
Bear River	114.50	ID/UT	Various	Various
Small East Hydro	26.50	ID/UT/WY	Various	Various

Hydroelectric Relicensing Impacts on Generation

Table A.11 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 will reduce generation available from these facilities.

Table A.11 – Estimated Impact of FERC License Renewals on Hydroelectric Generation

Year	Lost Generation (MWh)
2007	(154,370)
2008	(158,191)

Year	Lost Generation (MWh)
2009	(158,191)
2010	(158,191)
2011	(158,191)
2012	(168,035)
2013	(196,590)
2014	(196,590)
2015	(196,590)
2016	(212,383)
2017	(212,383)
2018	(212,383)
2019	(212,383)
2020	(212,383)
2021	(212,383)
2022	(212,383)
2023	(212,383)
2024	(212,383)
2025	(212,383)
2026	(212,383)

Note: Excludes the decommissioning of Condit, Cove, Powerdale, and American Fork.

Generation Resources

Table A.12 lists operational profile information for the PacifiCorp generation resources, including plant type, maximum megawatt capacity, ownership share, location, retirement date, and FERC Form 1 heat rates. Lake Side's heat rate has been approximated based on design expectations.

Table A.12 – Thermal and Renewable Generation Facilities

Plant	Maximum MW (PacifiCorp Share)	State	PacifiCorp Percentage Share	Retirement Date ^{1/}	Heat Rate (Btu/kWh)
Coal-fired					
Carbon 1	67	Utah	100%	2020	11,497
Carbon 2	105	Utah	100%	2020	11,497
Cholla 4	380	Arizona	100%	2025	10,815
Colstrip 3	74	Montana	10%	2029	10,870
Colstrip 4	74	Montana	10%	2029	10,870
Craig 1	83	Colorado	19%	2024	10,208
Craig 2	83	Colorado	19%	2024	10,208
Dave Johnston 1	106	Wyoming	100%	2020	11,047
Dave Johnston 2	106	Wyoming	100%	2020	11,047
Dave Johnston 3	220	Wyoming	100%	2020	11,047
Dave Johnston 4	330	Wyoming	100%	2020	11,047
Hayden 1	45	Colorado	24%	2024	10,571

Plant	Maximum MW (PacifiCorp Share)	State	PacifiCorp Percentage Share	Retirement Date ^{1/}	Heat Rate (Btu/kWh)
Hayden 2	33	Colorado	13%	2024	10,571
Hunter 1	403	Utah	94%	2031	10,508
Hunter 2	259	Utah	60%	2031	10,508
Hunter 3	460	Utah	100%	2031	10,508
Huntington 1	445	Utah	100%	2025	10,099
Huntington 2	450	Utah	100%	2025	10,099
Jim Bridger 1	353	Wyoming	67%	2026	10,569
Jim Bridger 2	353	Wyoming	67%	2026	10,569
Jim Bridger 3	353	Wyoming	67%	2026	10,569
Jim Bridger 4	353	Wyoming	67%	2026	10,569
Naughton 1	160	Wyoming	100%	2022	10,426
Naughton 2	210	Wyoming	100%	2022	10,426
Naughton 3	330	Wyoming	100%	2022	10,426
Wyodak 1	280	Wyoming	80%	2028	11,597
Gas-fired					
Currant Creek	541	Utah	100%	2040	7,327
Gadsby 1	60	Utah	100%	2017	11,590
Gadsby 2	75	Utah	100%	2017	11,590
Gadsby 3	100	Utah	100%	2017	11,590
Gadsby 4	40	Utah	100%	2027	11,556
Gadsby 5	40	Utah	100%	2027	11,556
Gadsby 6	40	Utah	100%	2027	11,556
Hermiston 1 ^{2/}	124	Oregon	50%	2031	7,222
Hermiston 2 ^{2/}	124	Oregon	50%	2031	7,222
Lake Side ^{3/}	544	Utah	100%	--	6,939
West Valley 1	40	Utah	100%	2008	10,694
West Valley 2	40	Utah	100%	2008	10,694
West Valley 3	40	Utah	100%	2008	10,694
West Valley 4	40	Utah	100%	2008	10,694
West Valley 5	40	Utah	100%	2008	10,694
Renewables and Other					
Blundell (Geothermal) ^{4/}	23	Utah	100%	2033	--
Foote Creek (Wind)	33	Wyoming	79%	2019	--
Leaning Juniper (Wind)	101	Oregon	100%	2031	--
James River (CHP)	30	Washington	100%	2016	7,200
Little Mountain (CHP)	14	Utah	100%	2009	16,980

1/ Plant lives are currently being reviewed for compliance with future environmental regulations.

2/ Remainder of Hermiston plant under purchase contract by the company for a total of 248 MW.

3/ Currently under construction; expected June 2007 start date.

4/ Planned Blundell bottoming-cycle upgrade of 11 MW in 2008.

Demand-Side Management

This section provides tabular statistics for PacifiCorp’s Class 1, 2, 3 and 4 demand-side management programs. For more information on demand-side management programs, see the following:

- Chapter 4 describes each of the demand-side management program classes.
- Chapter 4 summarizes how each of the Classes of demand-side management resources was incorporated in the portfolio simulation and analysis process.

Class 1 Demand-Side Management

Table A.13 details the base case Class 1 demand-side management programs. Peak load reductions for 2007-2016 are shown by program within each state.

Table A.13 – Class 1 Demand-Side Management Programs

Demand-side management program	Description	Program Contribution (Megawatts)	Availability
Irrigation Load Control	Incentive program for Idaho irrigation customers to participate in pumping load control program during the irrigation season.	50 megawatts in 2007 continuing for 10 years.	ID
Residential and Small Commercial Air Conditioner Load Control Program –“Cool Keeper”	Turn-key load control network financed, built, operated and owned by a third party vendor through a pay-for-performance contract. This program may be expanded in size or expanded into other jurisdictions within this planning period.	90 megawatts by 2007 contracted for through 2013.	UT
Irrigation Load Control	Incentive program for Utah irrigation customers to participate in pumping load control program during the irrigation season	12 megawatts in 2007 continuing for 10 years.	UT

Note: The company discontinued Utah’s commercial lighting load control program in August of 2006 following the program’s inability to reach its targeted curtailment milestones.

Class 2 Demand-Side Management

Since the 2004 IRP, more current Class 2 data has been incorporated into the 2007 IRP Class 2 DSM in the system load forecast. Adjustments, which increased savings, include the proposed implementation of Wyoming programs and the introduction of the Home Energy savers program for residential customers in Idaho, Washington and Utah in 2006 and proposed for California and Wyoming in 2007. The Energy Trust of Oregon has completed another resource assessment which reduces their expected contributions from their programs over the planning period. Changing federal standards have reduced air conditioning savings available from the Utah Cool Cash program as well as have impacted other program forecasts. The Utah Load Lightener program, which was expected to contribute energy efficiency results in addition to load management opportunities, was removed to reflect cancellation of the program in early 2006. Business customer programs have been adjusted to reflect the decrease in savings associated with short payback work drying up and the increased time to acquire the higher complexity savings.

Table A.14 defines the Class 2 programs. Table A.15 provides base case Class 2 demand-side management program savings for calendar years 2007-2016.

Table A.14 – Class 2 Demand-Side Management programs

Demand-side Management Program	Description
Energy FinAnswer (incentive program)	Engineering and incentive package for improved energy efficiency in new construction and comprehensive retrofit projects in commercial, industrial and irrigation sectors. Incentives are based on \$/kilowatt hour and \$/kilowatt reductions.
Energy FinAnswer (loan program)	Engineering and financing package for improved energy efficiency in new construction and retrofit projects in the commercial, industrial and irrigation sectors.
FinAnswer Express	Incentives for single measure new construction and retrofit energy-efficient projects in commercial, industrial and irrigation sectors. Incentives are based on a prescriptive (pre-determined) amount dependent on measures installed.
Recommissioning	Building tune-up services designed to provide customers with low to no cost actions they can take to improve the efficiency of their existing equipment or facilities.
Self-Direction Credit	Provides large business customers the opportunity to receive credits to offset the Customer Efficiency Services charge for qualified "self-investments" in efficiency and related demand side management projects.
Irrigation Efficiency	Three part program. Nozzle exchange, pump check and water management consultation, and pump testing that includes a system audit function. Depending on the state, incentives for system re-design and replacements are offered or the project is referred to the Energy FinAnswer program.
Efficient Air Conditioning Program – “Cool Cash”	Provide customer incentives for improving the efficiency of air conditioning equipment and/or maintaining or converting air conditioning equipment to evaporative cooling technologies.
Residential New Construction – “Energy Star Homes”	Third party delivered program providing incentives for home builders to construct single and multi-family homes that exceed energy code requirements. Homes are required to have more efficient cooling equipment and a mix of improved shell measures (windows and insulation) to be eligible for incentives. Additional incentives will be available for improved lighting and evaporative cooling.
Appliance Recycling Program	An incentive program designed to environmentally and cost-effectively remove inefficient refrigerators and freezers from the market.
Low-Income Weatherization Program	The company partners with community action agencies to provide no cost residential weatherization services to income qualifying households. Program may incorporate energy education depending on the state.
Home Energy Savers Program	A broad based residential program offering customer incentives for the purchase of energy efficient lighting, equipment, appliances, insulation and energy efficient practices e.g. air conditioner tune-ups or duct sealing. The program measures may vary between states due to measure specific programs available in some states e.g. Utah’s air conditioning efficiency program, “Cool Cash”.
Energy Education	Program provides 6th graders with energy efficiency curriculum and home energy audit kits that include instant savings measures i.e. compact florescent lights, shower-heads, temperature check cards, etc. This program is currently only available in Washington.

Demand-side Management Program	Description
Northwest Energy Efficiency Alliance (NEEA)	A series of conservation programs sponsored by utilities in the region and delivered through NEEA designed to support market transformation of energy efficient products and services in Oregon, Washington, Idaho and Montana. Programs include manufacturer rebates on compact fluorescent bulbs to building operator certification courses.
Energy Trust of Oregon (ETO)	Energy education and conservation measures implemented by the Energy Trust of Oregon with funding from the three percent public purpose charge paid by Oregon customers. The non-governmental delivery agent under contract with the Oregon Public Utility Commission was created in March of 2002 as part of the state's electric industry restructuring legislation, Senate Bill 1149.

Table A.15 – Class 2 Demand-Side Management Service Area Totals – All States, All Programs

(Calculated at the generator)

PacifiCorp – Class 2 Service Area Total				
Calendar Year	MWa First Year	MWh First Year	MWa Cumulative	MWh Cumulative
2007	29.17	256,517	29.17	255,517
2008	28.22	247,197	57.12	500,399
2009	24.49	214,558	80.80	707,775
2010	23.66	207,254	97.85	857,169
2011	22.88	200,416	119.33	1,045,329
2012	22.63	198,214	140.87	1,234,039
2013	22.58	197,844	163.12	1,428,948
2014	21.68	189,932	184.80	1,618,835
2015	21.15	185,259	205.94	1,804,051
2016	20.81	182,305	226.75	1,986,311

PacifiCorp – Class 2 Program Totals				
Calendar Year	MWa First Year	MWh First Year	MWa Cumulative	MWh Cumulative
2007	18.67	164,537	18.67	163,537
2008	19.22	168,357	37.62	329,579
2009	16.89	147,982	53.70	470,379
2010	14.86	130,166	61.95	542,685
2011	14.08	123,328	74.63	653,757
2012	13.63	119,374	87.17	763,627
2013	13.08	114,624	99.92	875,316
2014	12.18	106,712	112.10	981,983
2015	11.65	102,039	123.74	1,083,979
2016	11.31	99,085	135.05	1,183,019

Energy Trust of Oregon Total				
Calendar Year	MWa First Year	MWh First Year	MWa Cumulative	MWh Cumulative
2007	10.50	91,980	10.50	91,980
2008	9.00	78,840	19.50	170,820
2009	7.60	66,576	27.10	237,396
2010	8.80	77,088	35.90	314,484
2011	8.80	77,088	44.70	391,572
2012	9.00	78,840	53.70	470,412
2013	9.50	83,220	63.20	553,632
2014	9.50	83,220	72.70	636,852
2015	9.50	83,220	82.20	720,072
2016	9.50	83,220	91.70	803,292

Class 3 Demand-Side Management

Table A.16 defines the company’s Class 3 programs. Class 3 programs are treated as reliability resources and are not included within the company’s base resources.

Table A.16 – Class 3 Demand-Side Management Programs

Demand-Side Management Class 3 Program	Description
Energy Exchange program	Web based notification program that allows participating customers to voluntarily reduce their electric usage in exchange for a payment at times and at prices determined by the company. The program is available to customers with loads equal to or greater than 1 megawatt as measured anytime within the last 12 months. The company is considering program revisions that among other program design changes may expand the program to customers with loads of less than 1 megawatt.
Oregon Time of Use program	Senate Bill 1149 portfolio offering for residential plus greater than 30 kilowatt commercial and irrigation customers. Program enables customers to potentially reduce their energy costs by shifting the bulk of their energy usage to off-peak periods year-round.
Oregon Critical Peak Pricing pilot	Still under development as of the writing of this report, the company has agreed to a critical peak pricing pilot in Oregon fashioned after California’s investor owned utilities state-wide pricing pilot program. The program will likely be offered to residential and small commercial customers and be run for a two year period as the company collects information on the customer acceptance, behavioral performance, and cost-effectiveness of a larger offering.
Idaho Time of Day program – business and farm load customers	A program available to general service customers (non-residential, non-irrigation, non-street lighting and non-area lighting) with a maximum power requirement of 15,000 kilowatts or less. It encourages off-peak usage through tariff pricing.
Idaho Time of Day program – residential customers	A program available to residential customers (120 or 240 volt service with a single kilowatt hour meter). It encourages off-peak usage through tariff pricing.

Demand-Side Management Class 3 Program	Description
Utah Time of Day program – residential customers	A pilot program (1,000 customers) available to residential customers (120 or 240 volt service with a single kilowatt hour meter). It encourages off-peak usage through tariff pricing.
Interruptible contracts	The company has interruptible service agreements with a few major special contract customers that allow for service interruption during periods of system resource inadequacies and in some cases during periods of high market prices (economic dispatch).

Class 4 Demand-Side Management

Table A.17 defines the company’s Class 4 programs. Class 4 program resources are naturally taken into consideration through the development of the company’s integrated resource planning load forecasts.

Table A.17 – Class 4 Demand-Side Management Programs

Demand-Side Management Class 4 program	Description
“Do the bright thing” energy efficiency awareness and education advertising	General advertising messages that focus on low to no cost efficiency and load management tips and information encouraging customers to “Do the bright thing”. Campaign activity increases during seasonal peak periods utilizing radio, newspaper, buses, customer newsletters, and other media channels. The umbrella tag line is utilized by some of our Class 2 program vendors in their advertising efforts and the general advertising often directs customers to available incentive programs to assist them in their energy efficient pursuits.
PowerForward program	A state of Utah program supported by company and other state utilities that issues public service announcements in a stop light manner to alert customers of critical peak usage situations and requests customers to curtail non-essential loads during yellow and red alerts.
Residential do-it-yourself audit	Web accessible do-it-yourself paper audit designed to assist customers in identifying how they use energy today and providing them economically based recommendations on how to improve the energy efficiency of their homes. Customers can fill-out the audit online or mail in a copy of the completed audit. The company will complete the audit analysis and mail customers their results.
Oregon residential web audit	Web based do-it-yourself audit designed to assist customers in identifying how they use energy today and providing them economically based recommendations on how to improve the energy efficiency of their homes. The program is funded by the Oregon’s public purpose fund monies and operated by the Energy Trust of Oregon. A link to the program is found on the Pacific Power website.
Wyoming residential and small commercial energy advisor website.	Web based conservation advisor and energy advisor programs designed to assist customers in identifying how they use energy today and providing them economically based recommendations on how to improve the energy efficiency of their homes. The program is offered by the Wyoming Energy Conservation Network through a grant that was supported by PacifiCorp. A link to the program is found on the Rocky Mountain Power website.
Energy Education	Although this program is classified as a Class 2 resource due to its energy saving kit and associated savings, the program revolves around energy education, which is a Class 4 attribute. The program provides 6th graders with energy efficiency curriculum and home energy audit kits that include instant savings measures i.e. compact florescent lights, showerheads, temperature check cards, etc. This program is currently only available in Washington.

Transmission System

Topology

PacifiCorp uses a transmission topology consisting of 15 bubbles (geographical areas) in the East and nine bubbles in the West designed to best describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Bubbles are linked by firm transmission paths. The transfer capabilities between the bubbles represent PacifiCorp Merchant function’s firm rights on the transmission lines. Figure A.6 shows the IRP transmission topology.

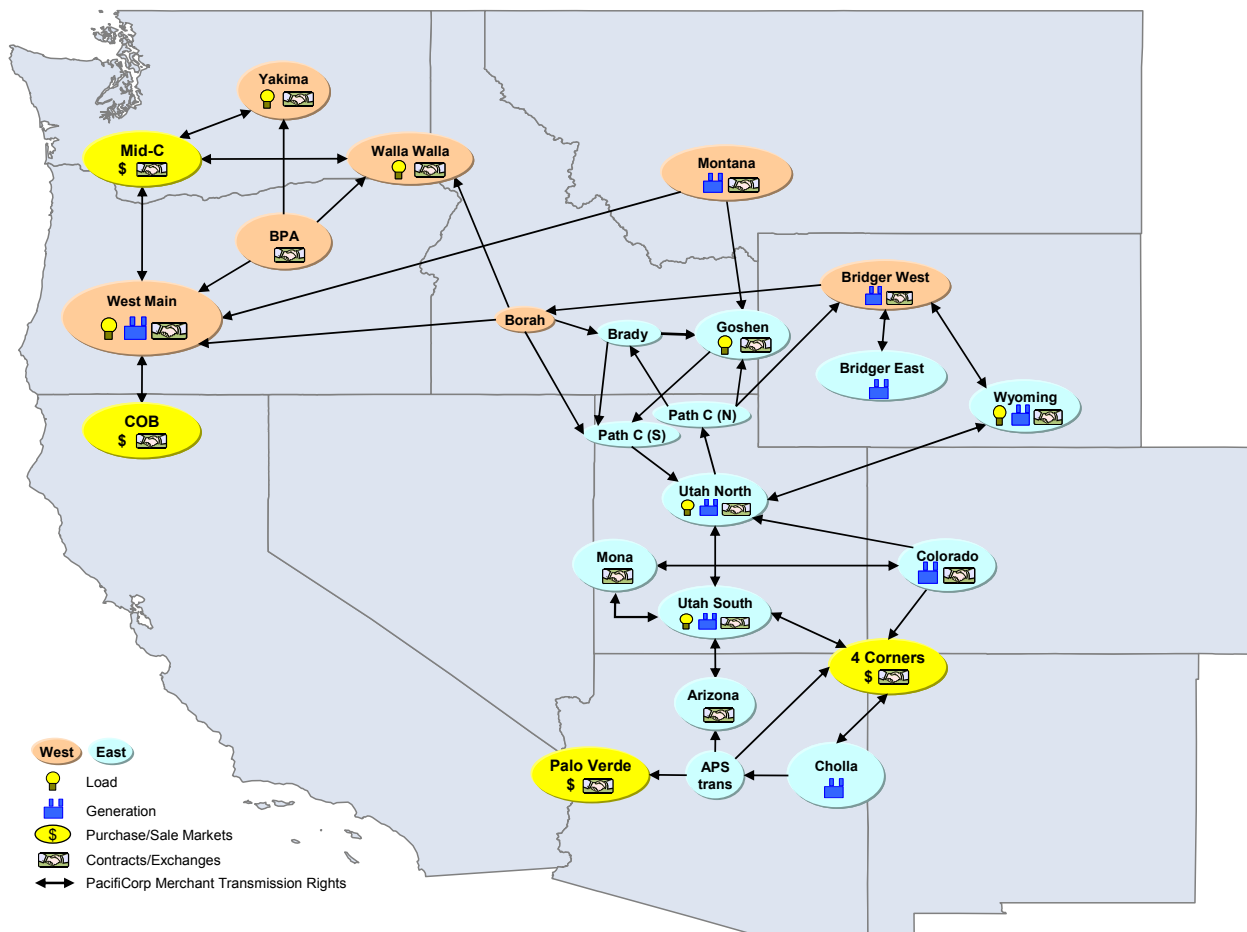
Losses

Transmission losses are netted in the loads as stipulated in FERC form 714 (4.48% real loss rate, schedule 9).

Congestion Charges

Transmission charges associated with a congestion pricing regime are not modeled. A detailed analysis of the impacts of congestion pricing will be undertaken in a future IRP when details concerning such pricing become available.

Figure A.6 – IRP Transmission System Topology



APPENDIX B – DEMAND SIDE MANAGEMENT PROXY SUPPLY CURVE REPORT

This appendix contains the report Demand Side Management Proxy Supply Curve Report received from Quantec, LLC as requested by PacifiCorp to support demand side management resource modeling in the 2007 Integrated Resource Plan.

The original report is provided in an attached document:
“Quantec-DRProxyCurve-FinalReport_090706.doc”

Final Report

Demand Response Proxy Supply Curves

Prepared for:
PacifiCorp

September 8, 2006



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I. Introduction

This report summarizes the results of an assessment of technical, market, and achievable potentials for demand response (DR) resources for PacifiCorp's system overall and its two control areas: West (California, Oregon, Washington), and East (Idaho, Utah, Wyoming). The results of this assessment form the basis for producing proxy supply curves for Class I and Class III demand-side management (DSM) resources, which will be incorporated into PacifiCorp's 2006 integrated resource plan (IRP).

The project's key objectives included: meeting PacifiCorp's IRP regulatory requirements; addressing public comments regarding comparable treatment of DR resources, with respect to power production options in PacifiCorp's resource portfolio evaluation; and assisting the company in further refining DR opportunities. Specifically, the project is intended to address an Oregon Public Utility Commission (OPUC) 2004 IRP requirement to evaluate Class I and Class III DSM resources, using a supply curve approach for portfolio modeling in PacifiCorp's 2006 IRP. In 2007, PacifiCorp plans to complete a more detailed assessment of DSM potentials, providing state-specific results. Therefore, this project is to be considered preliminary, and to serve as a "proxy" for the DR portion of that study.

The resulting supply curves show the price/quantity relationship for various categories of DR strategies and options within Class I and Class III DSM resources, as defined by PacifiCorp. As part of this project, to facilitate the economic screening of alternative DR options, research was also conducted regarding current utility practices in valuation of DR resources, with an emphasis on identifying key value drivers used in this evaluation.

This report is organized in five parts. The remainder of this chapter provides a general overview of DR resources, as well as the specific program concepts used in this study. Section II describes the results of research on DR value factors and valuation methods. Section III reports the results of the DR potential assessment. Section IV describes the general approach and methodology for estimating resource potentials. Detailed data and assumptions used to derive resource potentials for each specific DR resource are described in Section V.

Demand-Response Resources

Demand-response resources are comprised of flexible, price-responsive customer loads that may be curtailed in whole or in part during system peak load periods, when wholesale market prices exceed the utility's marginal power supply cost, or in the event of a system emergency. Acquisition of DR resources may be based on either reliability considerations or economic/market objectives. Demand response objectives may be met through a broad range of price-based (e.g., time-varying rates and curtailable rates) or incentive-based (e.g., direct load control) strategies. For the purpose of this project, DR is defined based on PacifiCorp's characterization in terms of two distinct classes of firm and non-firm resource options:

Class I (Firm) DSM Resources

This class of DR strategies allows either direct or scheduled interruption of electrical equipment and appliances such as water heaters, space heaters, central air-conditioners, commercial energy management systems, and irrigation pumps. Programmatic options in this class of resources fall into the four following categories:

- Fully dispatchable programs, 10 minute or less response, up to 87 hours annually (e.g., direct curtailment of residential air conditioning, water heating, space heating)
- Fully dispatchable programs, over 10 minute response, up to 87 hours annually (e.g., commercial energy management system coordination)
- Scheduled firm up to 170 hours annually (e.g., irrigation load curtailment)
- Scheduled firm at 360 or more hours annually (e.g., thermal energy storage)

Pre-determined incentive payments are typically the main instrument for compensating participants in this class of programs.

Class III (Non-Firm) DSM Resources

Demand response resources in this class differ from those in Class I in that their dispatch is outside the utility's control and, therefore, less reliable or "firm." Resources in this class include curtailable rate programs, time-varying prices (time-of use, real-time pricing, critical peak pricing), and demand buyback or demand bidding programs. Incentives are provided to participants either as a special tariff (curtailable rates, time-varying prices) or per-event payments (demand buyback).

Although residential seasonal programs such as Customer Energy Challenge are considered Class III resources, they are not included in this analysis. Arguably, such programs serve better as contingency resources during periods when energy prices are projected to be high and expected to stay high for an extended period of time, rather than as capacity relief resources.

Program Concepts

Before developing resource potential estimates, it is important to consider how each resource is likely to be structured as a demand response product or program. Using the definitions of Class I and Class III resources above, program concepts were developed as a framework for estimating market potential. For the purpose of this assessment, five specific program concepts were formulated, as described below.

Fully Dispatchable

Often referred to as direct load control (DLC), these fully-dispatchable programs are designed to reduce the demand during peak periods by turning off equipment or limiting the "cycle" time (i.e., frequency and duration of periods when the equipment is in operation) during system peak. The offerings for the residential sector are seasonally divided, while the potential with large

commercial and industrial customers typically focus on summer cooling loads only. Three program concepts in this category of resources were included in the analysis:

- **Winter.** Direct load control of water and space heating during winter are the program options considered in this class. This program would be dispatched during the morning and evening peak hours. The largest potential for such a program will be in the West control area because of the higher saturation of electric space heating. Incentives are generally paid on a monthly basis. Although there are no large scale DLC programs in the Northwest, Portland General Electric (PGE) and Puget Sound Energy (PSE) have both studied implementation through pilot programs. Nationally, there are many utilities with space and/or water heating controls, including Duke Power, Wisconsin Power and Light, Great River Energy, and Alliant Energy.
- **Summer.** The main DR product in this group is direct load control of air-conditioning units¹, which are typically dispatched during the hottest summer days, and are common place due to the relatively high summer loads in warm climates. PacifiCorp currently pays monthly incentives to residential and small commercial participants in Utah’s Cool Keeper AC Load Control program. There is approximately 130 MW of connected load for this program. Using a 50% cycling dispatch strategy, approximately half can be expected during an event. In addition to those utilities listed above, Nevada Power, Florida Power and Light, Alliant Energy, and the major investor-owned-utilities in California run air conditioner direct load control programs (e.g., Sacramento Municipal Utility District and San Diego Gas and Electric).
- **Large Commercial & Industrial.** Direct control of large commercial and industrial (C&I) customers requires coordination with the existing energy management systems (EMS). The focus of this program is adjustment of the heating, ventilation, and air conditioning (HVAC) equipment during the top summer hours. Incentives are generally paid on a per-kW or per-ton (of cooling equipment) basis. Some utilities running comparable programs include Florida Light & Power, Hawaiian Electric, and Southern California Edison.

Scheduled Firm

Program strategies that provide consistent reductions during pre-specified hours target customers with usage patterns and technology that allow scheduled shifting of consumption from peak to off-peak periods.

- **Irrigation Pumping.** Irrigation load control is a candidate for summer DR due to the relatively low load factor (approximately 30%) of pumping equipment and the coincidence of these loads with system summer peak. Through PacifiCorp’s irrigation load control program, customers subscribe in advance for specific days and hours when their irrigation systems will be turned off. Load curtailment is executed automatically based on a pre-determined schedule through a timer device. Although a total of 100 MW

¹ Although it may be possible to add control of electric hot water heating to this summer program, this study does not address this option due to the declining saturations of electric hot water heating and the relatively low peak coincident demand during summer.

is contracted with this program, only half is available due to the alternating schedules of program participants. In the Northwest, Bonneville Power Administration (BPA) has run a pilot irrigation program (on a dispatch, rather than scheduled, basis) and Idaho Power has a program similar to that of PacifiCorp.

- **Thermal Energy Storage.** For small commercial and industrial customers, it is possible to have thermal energy storage (TES) cooling systems that produce ice during off-peak periods, which is then used during the on-peak period to cool the building. The system is programmed to use ice-cooling during pre-specified times (typically six hours per day, from April to October) and participants are given incentives on a per-kW or per-ton-of-cooling basis.

Curtable Rates

Curtable rate options have been offered by many utilities in the United States for many years. These programs are designed to ease system peak by requiring that customers shed load (in part or whole) by a set amount or to a set level (e.g., by turning off equipment and/or by on-site generation) when requested by the utility. Participants are either provided with a fixed rate discount or variable incentives, depending on load reduction; penalties are often levied for participants who do not respond to curtailment events. Large commercial and industrial customers are the target market for those programs that address PacifiCorp's summer system peak. Many utilities provide a broad range of program options, including Duke Power, Georgia Power, Dominion Virginia Power, Pacific Gas and Electric, ConEd, Southern California Edison, MidAmerican, and Wisconsin Power and Light.

Critical Peak Pricing

Critical Peak Pricing (CPP) rates only take effect a limited number of times during the year. In times of emergency or high market prices, the utility can invoke a critical peak event, where customers are notified and rates become much higher than normal, encouraging customers to shed or shift load. Typically, the CPP rate is bundled with a time-of-use rate schedule, whereby customers are given a lower off-peak rate as an incentive to participate in the program. Customers in all customer classes (residential, commercial, and industrial) may choose to participate in a CPP program, although there are certain segments in the commercial sector that are less able to react to critical peak pricing signals. Currently, there are no CPP programs being offered by Northwest utilities. Peak pricing is, however, being offered through experimental pilots or full-scale programs by several organizations in the United States, notably Southern Company (Georgia Power), Gulf Power, Niagara Mohawk, California utilities (SCE, PG&E, SDG&E), PJM Interconnection, and New York ISO (NYISO). Adoption of CPP has not been as widespread in the Western states as they have in the East. In the Pacific Northwest, this may be partly explained by the generally milder climate and the fact that, due mainly to large hydroelectric resources, energy, rather than capacity, tends to be the constraining factor.

Demand Buyback/Demand Bidding

Demand buyback and/or bidding (DBB) products are designed to encourage customers to curtail loads during system emergencies or high price periods. Unlike curtailment programs, customers have the option to curtail power requirements on an event-by-event basis. Incentives are paid to participants for the energy reduced during each event, based primarily on the difference between market prices and the utility rates. All major investor-owned utilities in the Northwest and Bonneville Power Administration have offered variants of this option, beginning in 2001. PacifiCorp's current program, Energy Exchange, was used extensively during 2001 and resulted in maximum reduction of slightly over 40 MW in that period. Demand reductions from PacifiCorp's current program are approximately 1 MW. Demand buyback products are common in the United States and are being offered by many major utilities. The use of DBB offerings as a means of mitigating price volatility in power markets is especially common among independent system operators including CAISO, NYISO, PJM, and ISO-NE. However, DBB options are not currently being exercised regularly due to relatively low power prices.

II. Valuation of Demand Response Resources

Overview

In the Northwest and elsewhere in the country, valuation of DR programs has been the subject of much debate among utility industry experts. Although there is broad agreement on the existence and relevance of a wide range of benefits arising from DR, there is little agreement on how and to what extent these benefits can be attributed to specific DR programs and what metrics might be used to quantify them. In response to this, in 2005 the Northwest Power and Conservation Council sponsored a series of workshops to identify and enumerate value attributes of DR resources and to develop a consistent methodology for their valuation. The Demand Response Research Center in California recently commissioned two parallel studies to investigate alternative frameworks for valuation and cost-effectiveness analysis of DR products.

As part of this study, we conducted a thorough search of DR literature, evaluation reports, and utility filings, followed by informal interviews with several industry experts to investigate current practices for evaluating DR resources. The results of this analysis are intended to inform PacifiCorp's process for screening DR resource options and how they might be incorporated in its integrated resource plan. We begin this section with a review of potential benefits and value factors ascribed to DR, discuss the current practices and the basis for valuation of these benefits, and then consider alternative approaches for incorporating DR options in the integrated resource planning process.

Benefits of Demand Response

There are many different views on the types and the relative importance of value factors associated with DR. Industry experts agree on at least three general categories of benefits from DR: economic, system reliability, and environmental (Hirst 2001).

Economic Benefits. There is a host of economic benefits to the utility, the consumers, and the power system as a whole that are presumed to arise from DR. Some of these benefits are more tangible and more readily quantifiable than others. Cost avoidance and cost reduction are the main economic drivers for DR. Demand response allows utilities to avoid or defer incurring costs for generation, transmission, and distribution, including capacity costs, line losses, and congestion charges. Economic benefits may also accrue directly to participants in the form of incentives, rate discounts, and greater ability to adjust their loads to prices, thereby gaining greater control over their energy use and managing their energy costs (Braithwait, 2003). DR has also been credited with several harder to quantify economic benefits, such as creating a hedge against market exposure (price objectives), helping create a more elastic demand curve by sending appropriate price signals (elasticity objectives), and reducing the overall market price by alleviating pressure on reserves (market efficiency objectives) (Ruff, 2002).

System Reliability Benefits. Demand response reliability considerations are those meant to ensure reliability in power supply and delivery during system emergencies by providing the ability to shed load under emergency conditions. Customer demand management can enhance

reliability of the electric supply and delivery systems by providing the utility with the means to better balance loads with supply during system emergencies and/or high-use periods. In this context, DR can help improve the adequacy and security of the power supply and delivery (T&D) systems by augmenting the utility's ancillary services, such as supplemental reserve (Hirst, 2002).

Potential Environmental Benefits. Demand response resources promote the efficient use of resources in general. Depending on the generation fuel mix of the sponsoring utility, this can help reduce externalities in power generation and reduce emissions. Increasingly, utilities have begun to consider the potential effects of future carbon taxes in their DR product design.

Although this is by no means an exhaustive list of all potential benefits discussed in DR literature, it represents the most common set of benefits recognized by industry experts. Additional benefits such as risk management, market power mitigation, customer service, and third-party benefits (for example to aggregators and service providers) have also been cited as potential benefits of DR. These benefits, however, generally tend to be less pronounced and difficult to quantify (Peak Load Management Alliance, 2002). Approaches and current practices for evaluating DR resources and quantifying each of the above benefit categories are discussed below.

Resource Valuation Methods

Current practices in valuation of DR resources largely rely on an extension of the “Standard Practice Manual” (SPM) originally developed in California for evaluating energy-efficiency programs (California Public Utilities Commission, 2001). Of the four tests set forth in the latest version of the SPM, published in 2001, the total resource cost test (TRC), usually accompanied by the participant test, is the most common method used to screen DR resources by utilities (California Public Utilities Commission, 2003).² A clear instance of the application of SPM to the evaluation of DR resources is found in the California Public Utilities Commission's direction that the SPM be used as an option in evaluating DR, “since it allows an assessment of demand reductions from multiple viewpoints: society, customer, utility, and ratepayer.”

A review of current practices in valuation of DR benefits indicates that not all benefits discussed above are taken into account by utilities or system operators, mainly due to the fact they tend to be hard to quantify. Potential benefits of DR, common basis for their valuation, and the range of suggested values are summarized in Table 1. Current valuation methods and practices are discussed in greater detail below.

² The other tests are the Ratepayer Impact Measure (RIM) Test, Participant Tests, and the Program Administrator (or Utility) Test.

Table 1. Potential Benefits of Demand Response

Benefit Category	Value Factors	Basis for Valuation	Range of Values
Market-wide	<ul style="list-style-type: none"> Overall economic efficiency (better alignment of supply and demand) Reduction in average price of electricity in the spot market Reduced costs of electricity in bilateral transactions Reduced hedging costs, e.g., reduced cost of financial options Reduced market power Private entity (e.g. aggregator) benefits 	Not Quantified	Not Applicable
Utility System	<ul style="list-style-type: none"> Avoided capacity costs (generation) Avoided energy costs Avoided T&D losses Deferred grid system expansion 	Benchmarking (peaker unit) Benchmarking (market prices) Adders Marginal (local) T&D costs	\$50-\$85 Variable 6%-10% Variable
Customer	<ul style="list-style-type: none"> Incentives Reduced power bill (participants) Greater choice and flexibility 	Value of payment Rates, demand charges Cash-flow, Option model	Variable Variable Variable
Reliability Benefits	<ul style="list-style-type: none"> Increase in overall system reliability Value of insurance against low-probability/high-consequence events Option value (added flexibility to address future events) Portfolio benefits (increase in resource diversity) 	Change in LOLP Value of un-served energy (customer outage costs) Not Quantified Not Quantified	Not Available \$3-\$5 per kWh Not Applicable Not Applicable
Environmental Benefits	<ul style="list-style-type: none"> Avoided emissions Avoided future carbon taxes 	Environmental “adder” Not Quantified	8%-12% Not Applicable

Valuation of Economic Benefits

With the exception of participant tests, the application of the SPM tests rely on the concept of cost avoidance as the key mechanism for taking into account the economic value of DR. The TRC test, which is often used as the primary criterion for screening of DR resources, takes into account a variety of avoided costs associated with generation, transmission, distribution, and line losses. The avoided capacity and, to a lesser extent, energy costs are the principal economic benefits included in the test. Determination of avoided capacity and energy costs are most commonly based on a benchmarking method. In the case of avoided capacity costs, the approach relies on using average per-unit life cycle cost of a peaker resource (usually a combined- or simple-cycle gas turbine) as a benchmark for screening of DR options. Market price curves are the most commonly-used proxy for determination of avoided energy costs.

Avoided capacity costs tend to vary across utilities and the program to which they are applied. Regardless of how they are calculated, capacity costs used by most utilities surveyed fall in the range of \$50 to \$85 per kW-year. In a recent ruling, the California Public Utilities Commission

authorized an avoided cost of \$52 per kW as compared to the previously established avoided cost of \$85 per kW, based on the average life-cycle cost of a peaker plant method for screening and valuation of DR resources (CPUC, PG&E Application 05-06-028, 2005).

Avoided energy costs represent additional benefits from DR programs. Since most DR programs lead to a shift (rather than a reduction) in energy use, the energy benefits are typically measured in terms of on-peak/off-peak price differential. Other DR programs, such as DLC may result in reductions in energy use, since some portion of the foregone energy use may not be offset by additional consumption during the off-peak period. The latter benefits are especially important in evaluating DR programs from the participants' point of view, since they tend to directly affect bills. Avoided energy costs have been used to measure the benefits in a number of evaluations of DR programs in the Northwest.³ Avoided energy costs are also the sole basis for determination of payments in demand buyback and demand bidding programs. Indeed, incentives in all demand buyback programs are structured on the basis of market energy prices, rather than avoided capacity costs.

Benefits to the grid system generally fall into two categories: 1) avoided line loss; and 2) value of opportunities to defer system expansion. In the Northwest, both PacifiCorp and PGE have explicitly incorporated avoided T&D losses in their past evaluations of time-of-use and direct load control programs, and Bonneville Power Administration has explicitly included deferral of investments transmission system expansion in its system planning and valuation of DR programs.

Direct benefits to customers represent additional benefits likely to result from DR. These benefits generally appear in the form of incentive payments from the utility or lower bills resulting from reductions in demand charges, shift of demand to lower-priced, off-peak periods and potential energy savings. As discussed above, in the case of DR programs involving a shift in consumption, these benefits tend to be small. In many DR programs, such as time-of-use rates and load control/curtailment programs, portions of the foregone energy use during DR events (high rate or curtailment period) may not be compensated by higher use during off-peak period, thus resulting in net reductions in the customer's energy consumption.

Other potential benefits to customers, such as greater choice and "option value," are generally more difficult to quantify. Attempts at quantification of these benefits generally rely on either a discounted cash-flow analysis or an "option model" (see Sezgen 2005).

Valuation of System Reliability Benefits

The planning and screening of utility-sponsored DR programs typically have not included reliability benefits. But reliability has been the primary metric for valuation of DR programs offered by independent system operators (ISOs). Most of the seven established ISOs have been actively engaged in offering DR options. Since the primary goal of an ISO is to maintain system reliability, it stands to reason that valuation of their programs would be based on reliability

³ These include evaluations of irrigation load curtailment and pilot time-of-use programs offered by PacifiCorp, evaluations of residential time-of-use and direct load control programs by PGE, and Bonneville Power Administration's evaluation of remote irrigation load control.

benefits rather than avoided generation capacity. Indeed, evaluations of ISO-sponsored programs completed to date have focused almost exclusively on reliability benefits based on avoided congestion, valued in terms of the location-specific marginal transmission costs (LMC).

The general approach used in valuation of ISO-sponsored DR is based on two factors: 1) the difference between market power price and the DR program costs; and 2) the expected marginal value of increased reliability realized through assumed reductions in loss-of-load probability (LOLP) and its impact on the expected value of un-served energy (EVUE) as a function of the value of lost load (VOLL), that is:

$$EVUE = \text{Value of Lost Load (VOLL)} * \Delta \text{LOLP} * \text{Load at Risk}$$

The underlying concept in the evaluation approach is that the value of curtailable load (therefore the value of the DR programs that generate it) is a function of the “expectation” of future loss of load. This suggests that the actual value of DR programs stems primarily from their societal value as a hedge against low-probability, high-cost events and the associated outage costs to customers.

The NYISO and ISO-NE have both used this approach in evaluation of their DR products (RLW Analytics, 2005). Calculation of changes in LOLP and the value at risk are generally established on an event-by-event basis and tend to be highly variable. In its evaluations, the NYISO, for example, typically has assumed a VOLL of \$5.00/kWh (NYISO, 2004); and the PJM Interconnection recently proposed a VOLL of \$20/kWh. However, as data on several real-time pricing programs suggest, the VOLL tends to fall in the range between \$3/kWh and \$5/kWh (Barbose 2004, Violette 2006). Available estimates of VOLL are calculated from the customer’s or societal perspectives and are generally expressed in terms of energy, rather than capacity. Presumably, given the actual, program-specific hours of curtailment, it may be possible to convert these estimates to an equivalent capacity value.

Valuation of Environmental Benefits

Demand response has the potential to produce tangible environmental benefits by avoiding emissions from the operation of peak units as well as potential conservation effects (load shed versus load shift) during peak periods. Such environmental impacts, however, depend entirely on the emissions profile of the utility’s generation resource mix. It is also possible that reduced emissions during peak periods might be offset by increased emissions during off-peak periods, as well as from additional emissions from on-site, back-up generation at commercial and industrial facilities. Due partly to these complexities, potential environmental benefits are not currently being considered in valuation of utility-sponsored DR programs.

Treatment of DR Options in Integrated Utility Resource Planning

Classification of DR Options

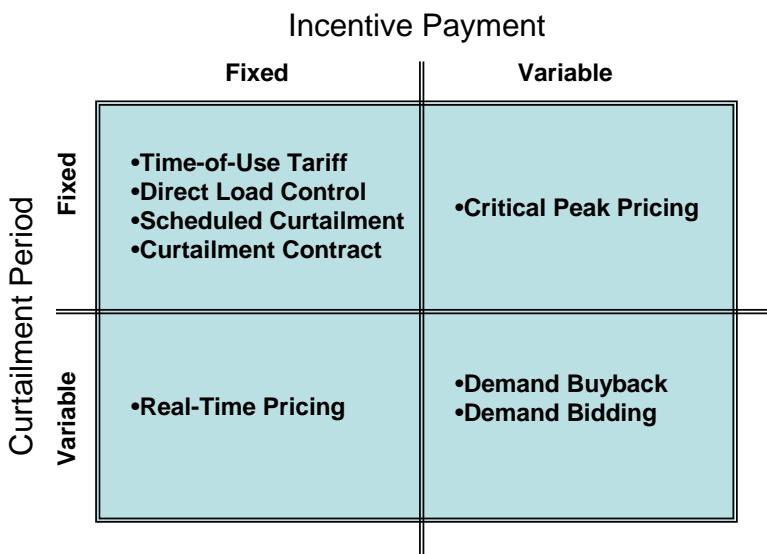
Values arising from DR options, and the manner in which they are incorporated in the integrated planning process may vary by the type of DR product and the entity that sponsors them. There have been several attempts at classification of DR programs. The most common approach to

classification of DR involves characterizing them according to the degree of the utility’s dispatch control. From this perspective, DR resources are generally categorized according to a “firm” versus “non-firm” dichotomy. Another approach, adopted in the recent report by the U.S. Department of Energy, classifies DR programs in terms of the basis on which participants are compensated and proposes two categories: tariff-based and incentive-based (DOE, 2006). A third approach, suggested in a recent study sponsored by the Rocky Mountain Institute (Rocky Mountain Institute, 2006), classifies DR resources along two dimensions: 1) the criteria that trigger a curtailment request by the utility (economic versus reliability); and 2) the method by which utilities motivate customers to participate in DR (load response versus price response).

These approaches, however, generally do not provide guidance as to how DR benefits and costs might be allocated or how various resources might be modeled in an integrated resource plan. Arguably, from a utility’s perspective, the most important benefits of DR are economic (reducing the overall supply cost) and reliability (offering an optional resource in case of system emergencies).

An alternative, and perhaps more appropriate, classification of DR would be in terms of the degree of variability in curtailment period and prices paid by the sponsoring utility.⁴ Under this scheme, DR resources are classified in terms of two dimensions: curtailment period and incentive payment. As shown in Figure 1, both period of curtailment and the level of incentives paid by the utility to motivate curtailment may be either fixed or variable. (See Neenan, 2006.)

Figure 1. Classification of Demand Response Programs



⁴ Time-of-use rates and critical peak pricing are examples of programs where both pricing period and price levels are fixed. Demand buy-back and demand bidding demand response strategies are examples of programs where both price periods and levels of payment are variable.

Time-of use, load control, scheduled curtailment, and curtailment contracts are examples of resources where both incentive payments and curtailment periods are fixed in advance. Although this group of programs offers more *predictable* prices and, to a lesser extent, amounts of reduction, they also pose a degree of price risk in that program prices are set in advance through the use of price forecasts rather than based on actual prices at the time of load reduction. Demand buyback and demand bidding, on the other hand, are resources where both curtailment period and incentive payments are variable.

Incorporating DR into the IRP Process

Much the same as energy efficiency resources, DR products may be incorporated into the IRP in two ways. The first approach, often referred to as “decrementing,” begins with pre-screening of DR resources for general cost-effectiveness based on an external benchmark (generally avoided capacity costs), decrementing the load forecast by the amount of DR resources that pass the screening, and solving for the true avoided cost as derived from the value of decremented load to the resource portfolio. The second approach entails simultaneous modeling of generation and DR resources in the context of an optimization or system expansion planning model and selecting the optimal, least cost, mix of resources. In our view, the latter approach is preferred in that it treats DR resources on a level playing field with supply options and forces the model to select from the most attractive, least-cost mix of resources regardless of their classification as supply or demand-side.

The main shortcoming of these approaches to valuation and integration of DR resources is that they generally focus on economic (cost-reduction) benefits of DR and ignore the reliability benefits. Moreover, the economic benefits of DR often are measured in terms of energy, rather than capacity, values. For most DR resources, the benefits ought to be evaluated primarily in terms of an alternative, “optional” capacity resource and secondary energy benefits (in terms of both reduced consumption and/or peak-off-peak energy costs differential). Regardless of the method used, it is important that the full range of economic values (including avoided capacity, energy, and T&D benefits, as well as reliability benefits) be fully considered in the screening and planning processes. Although the greatest value of DR options is likely to be on the generation side, additional benefits such as avoided T&D losses and reliability benefits may be incorporated in the valuation as utility-specific “adders.”

An additional shortcoming of these approaches is that they ignore the role of risk and uncertainty associated with various resource options. Clearly, there are technical (e.g. equipment failure) and market (e.g. program and event participation rates) uncertainties inherent in any demand-response option. These risks need to be explicitly taken into account in screening of DR resources. It is equally important in the context of IRP that the treatment of DR risks be symmetrical; that is, the screening process ought to also take into account upside risks of DR. Since DR resources are valued on the basis of expected future loads and power prices, future fluctuations in loads and avoided costs are likely to have a direct effect on the value of DR options.⁵

⁵ Portfolio management principles and techniques are being used in a limited way by some utilities to analyze uncertainties in the IRP process. This is particularly the case in designing standard renewable portfolios in several

In the context of IRP, joint consideration of economic (capacity and energy) and reliability benefits does, however, pose additional complexity. Since integrated resource planning processes are generally based on long-run resource needs, the value of DR hinges on its ability to displace some portion of the utility's peak demand. As pointed out in the Department of Energy's recent report, once DR resources are included in the utility's capacity resource mix, they become part of the planned capacity and are no longer available for dispatch during system emergencies (DOE, 2006). It is important, therefore, to distinguish between DR resources that serve the economic objectives and might be incorporated in the resource plan and those that are more appropriately set aside for reliability purposes. Certain DR resources, such as demand bidding or demand buyback, may be set aside as reliability options to be called upon during system emergencies.

Potential adverse customer impacts are additional considerations in DR planning. Clearly, once DR resources are incorporated in the planned capacity, the utility can maximize the value of DR resources by exercising these options to the maximum extent possible. However, the more frequently these options are exercised, the higher the likelihood of more severe disruptive impacts of the customers' operations. This will affect the customers' decision to participate in the DR program and thus reduce the market potential for DR.

jurisdictions. For a discussion of uncertainty in IRP and the portfolio management approach see Awerbuch (1993 and 2005). Also see Bolinger (2005) for a survey of current utility practices in portfolio design.

III. Demand Response Resource Potentials

The approach to estimation of resource potentials in this study distinguishes between three definitions of demand-response potential that are widely used in utility resource planning: technical, market, and achievable potentials. Technical potential assumes that all demand-response resource opportunities may be captured regardless of their costs or market barriers, notwithstanding obvious exceptions such as load control in mission-sensitive operations. Market potential, on the other hand, represents that portion of technical potential that is likely to be available over the planning horizon, given resource constraints and prevailing market barriers. Finally, achievable potential recognizes that not all of the market potential can be implemented due to the overlap (or interaction) among DR options targeted for the same sectors and/or end uses.

To the extent possible, we have sought in this study to obtain the most recent and reliable data on market prospects for various DR options, relying upon available resources from other utilities offering similar products. However, information and assumptions based on current demand response experiences and costs, no matter how accurate, are subject to future uncertainty. Therefore, the results of this study are to be viewed as preliminary and indicative rather than conclusive.

The general methodology and analytic techniques used in this study conform to standard practices and methods used in the utility industry. Given the scope and timeframe of this study, it was necessary to utilize a consistent and relatively simple methodology to effectively address PacifiCorp's immediate IRP needs. The methodology and inputs assumptions are fully described in Sections IV and V of this report.

Technical Potential

In the context of demand response, technical potential assumes that all applicable end-use loads, in all customer sectors, are at least partially available for curtailment, except those customer segments (e.g., hospitals) and end uses (e.g., restaurant cooking loads) that do not lend themselves to curtailment,⁶ and for those programs (e.g., direct load control) that utilize cycling strategies.

Table 2 provides for each customer class (industrial, commercial, irrigation and residential) the technical potential in MW at the system level. (Separate results for the East and West control areas are provided in Appendices 1 and 2.) From a strictly technical perspective, critical peak pricing is expected to have the largest potential due to its broad-based eligibility, followed by curtailable rates and demand buyback. In the absence of market constraints, these figures should

⁶ Although hospitals generally rely on some on-site generation capability, which may be called upon by the utility as a dispatchable resource, such resources are not being considered in this study. Arguably these units are likely to be needed by the host facility during the same period as the utility and are therefore unlikely to be made available for dispatch.

be viewed largely as estimates of “technical feasibility” only and a measure of the total load that is technically available for demand response.

Table 2. Technical Potential (MW), System

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	194	---	---	510	531	500
Commercial	---	55	50	-	93	133	232	130
Irrigation	---	---	-	381	---	---	---	---
Residential	374	351	-	---	---	---	618	---
Total	374	406	244	381	93	642	1,380	630
<i>% of System Peak</i>	<i>4%</i>	<i>5%</i>	<i>3%</i>	<i>5%</i>	<i>1%</i>	<i>8%</i>	<i>16%</i>	<i>7%</i>

To provide an illustration of the methods used to estimate technical potentials, the fully dispatchable winter program will be used. First, eligibility for this program is limited to residential customers due to low saturation of electric space and water heating in other customer classes. Next, PacifiCorp energy sales and system and end-use load shapes indicate that the total residential space and water heating loads during the top 87 hours of the winter average approximately 580 MW and 250 MW, respectively. Although DLC programs can fully interrupt this load when installed, it is assumed that a 50% cycling strategy is used, and only 90% of this is technically available to account for the fact that not all systems can be retrofitted with DLC equipment. Therefore, the system-level technical potential, as shown in Table 3, is 374 MW.

Market Potential

Market potential is the subset of technical potential that may reasonably be accessible by program strategies, accounting for market barriers and customers’ ability and willingness to participate in demand response programs. For the majority of demand response options, market potentials are estimated by adjusting technical potential by two factors: expected rates of “program” and “event” participation. For all programs options, estimates for both program and event participation are derived based on the experiences of PacifiCorp and other utilities offering similar programs. In the case of curtailable rates and demand buyback, market potentials are estimated based on observed price elasticity of load response. See Figure 2 for a comparison of technical and market potentials for various program options.

As shown in Table 3, curtailable rates have the highest market potential (144 MW), followed by summer DLC and irrigation.

Figure 2: Technical and Market Potential (MW), System

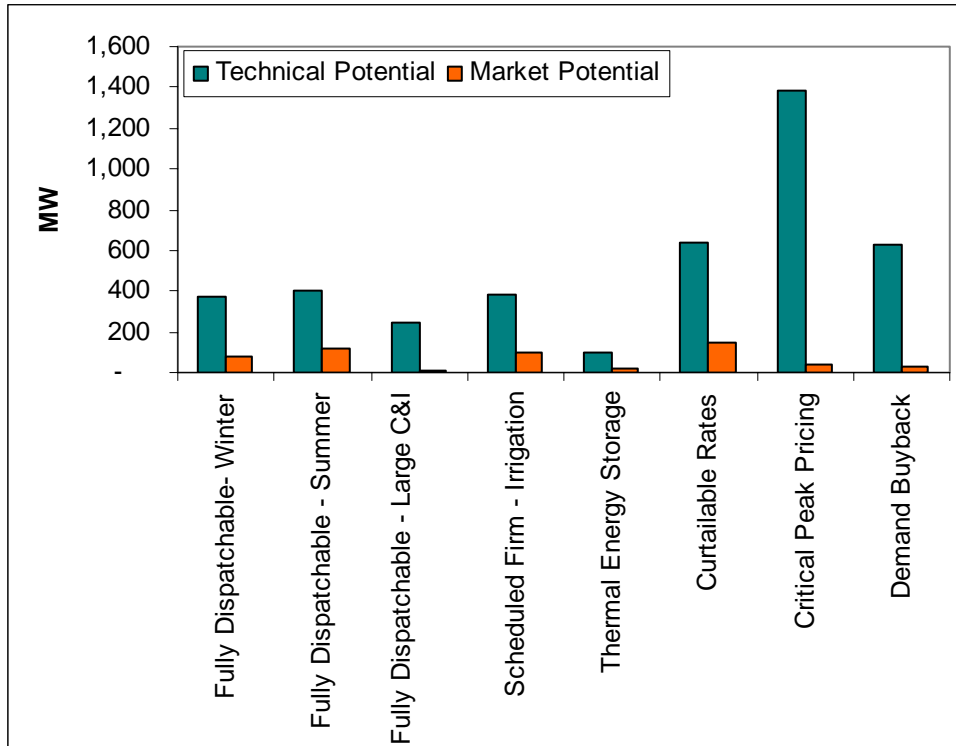


Table 3. Market Potential (MW), System

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	5	---	---	115	14	22
Commercial	---	3	1	---	19	30	6	6
Irrigation	---	---	---	95	---	---	---	---
Residential	75	118	---	---	---	---	17	---
Total	75	120	7	95	19	144	37	28
<i>% of System Peak</i>	<i>0.9%</i>	<i>1.4%</i>	<i>0.1%</i>	<i>1.1%</i>	<i>0.2%</i>	<i>1.7%</i>	<i>0.4%</i>	<i>0.3%</i>

For a fully dispatchable winter program, an expected load participation rate of 20% (based on experience of similar programs) and event participation rate of 100% are assumed. This assumption is based on the fact that, absent customers’ ability to override curtailment and no equipment failure, load interruption would occur once the load is dispatched by the utility.⁷

⁷ Reliability of direct load control systems is primarily a function of the type of equipment and communication systems used to affect control such as radio frequency, telephone networks, wide-area networks, or power line carrier systems. Historical experience with systems has shown that the assumption of a zero failure rate may be unjustified.

Based on these assumptions, this program could reasonably be expected to provide approximately 75 MW of load reduction for the PacifiCorp system.

Using price elasticity of load participation and a measure of commercial and industrial customers' willingness to participate in demand buyback, market potential for this option is estimated at 28 MW. As discussed in Section IV of this report, the elasticity estimates were calculated based on data available on 2000-'01 demand buyback program experience of Northwest utilities. Data available on PacifiCorp's 2000-'01 Energy Exchange program indicate approximately 40 MW of reduction at an average cost of approximately \$100 per MWh. The estimated 28 MW of future market potential may prove overly optimistic due to the dramatically different market conditions prevailing today. Reductions similar to those achieved in 2000-'01 could be difficult or impossible to repeat if electricity prices and customer concerns over energy market conditions continue to be low. Indeed, based on PacifiCorp's program records, operation of the Energy Exchange program during the past three years has resulted in a maximum reduction of no more than 1 MW.

Achievable Potentials

In analyzing levels of achievable potential it is important to take into account two factors: resource interactions and load reduction being achieved given existing programs. Achievable potentials, therefore, represent unique impacts of various DR program options net of the impacts of existing programs. Estimates of market potentials presented above provide "stand alone" estimates of potential. In calculating achievable potential, it is also important to take into account the interaction among DR programs that target the same customer sector and/or end uses within the same sector. Generally, interaction may be accounted for by first ranking competing programs by levelized cost and then allocating the market potentials based on an "availability" factor⁸.

For the purpose of this study, we have assumed that DBB and scheduled firm irrigation are fully available; therefore they have been assigned an availability factor of 100%. Since curtailable rates and dispatchable large C&I compete for the same target market as DBB, only a portion of their market potential will be available. In the residential and small commercial sector, the summer DLC program is fully available; however, thermal energy storage would only be partially available as it competes with the commercial sector DLC program option.

As shown in Table 4, the DR options considered in this analysis may be expected to provide 373 MW of capacity for the PacifiCorp system. In 2005, the PacifiCorp system peaked at 8,940 MW with 570 MW and 1,540 MW of load occurring during the top one percent and ten percent of the load duration curve. The estimated achievable potentials for DR provide the opportunity to offset 66% of the top one percent and 25% of the top ten percent of the system peak load.

⁸ Technically, this is the percentage of the market potential that remains after accounting for resource interactions. For example, a 25% availability factor would be multiplied by the market potential to arrive at the achievable potential on a program-by-program basis.

Summer DLC (120 MW), irrigation (95 MW), and curtailable rate (72 MW) are expected to provide the highest levels of achievable potential. Yet, approximately 114 MW of the identified potential is already under contract through PacifiCorp’s Cool Keeper (65 MW), irrigation load curtailment (48 MW), and Energy Exchange (1 MW), resulting in a remaining achievable potential of 259 MW. Therefore, in addition to achievable potential, Table 4 also provides potential net of current programs.

Table 4. Achievable Potential (MW) – System

	Fully Dispatchable			Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Achievable Potential	37	120	3	95	9	72	7	28	373
Current Program MW	---	65	---	48	---	---	---	1	114
Potential Net of Current Programs	37	55	3	47	9	72	7	27	259

Proxy Resource Supply Curves

Supply curves are constructed to show the relationship between the cumulative quantities of DR resources and their costs. Development of supply curves first requires the estimation of per-unit costs. Demand response strategies vary significantly with respect to both type and cost levels. Applicable resource acquisition costs for DR generally fall into two categories: 1) fixed direct expenses such as infrastructure, administration, maintenance and data acquisition; and 2) variable costs. In the category of fixed cost, this study distinguishes between initial development and on-going program administration and operation costs. Variable costs also fall into two categories: costs that vary by the number of participants (e.g., hardware costs) and those that vary by kW reduction (primarily incentives).

Although a large number of national programs were researched for this project, the reporting of costs, particularly development and ongoing administrative costs, were found to be either unavailable or difficult to measure. For the purposes of this study, to the extent possible, we have relied primarily on administrative costs associated with PacifiCorp’s other, similar programs, or have adopted rough estimates available from other utilities. See Section IV for specific cost assumptions for various DR options.

In developing proxy supply curves, all program costs were first allocated annually over the expected program life cycle (10 to 15 years) discounted by PacifiCorp’s real cost of capital at 5.1% to estimate the per-kW levelized⁹ costs for each resource. Resources were then ranked based on their levelized costs along the supply curve. Figure 3 displays per-unit costs for the various DR options.

⁹ Levelized costs represent the annual contract cost, per kW/year, for each DR option. This approach provides means for treating all DR on a consistent basis with supply alternatives in the IRP framework.

Figure 3: Levelized Resource Costs (\$/kW/year)

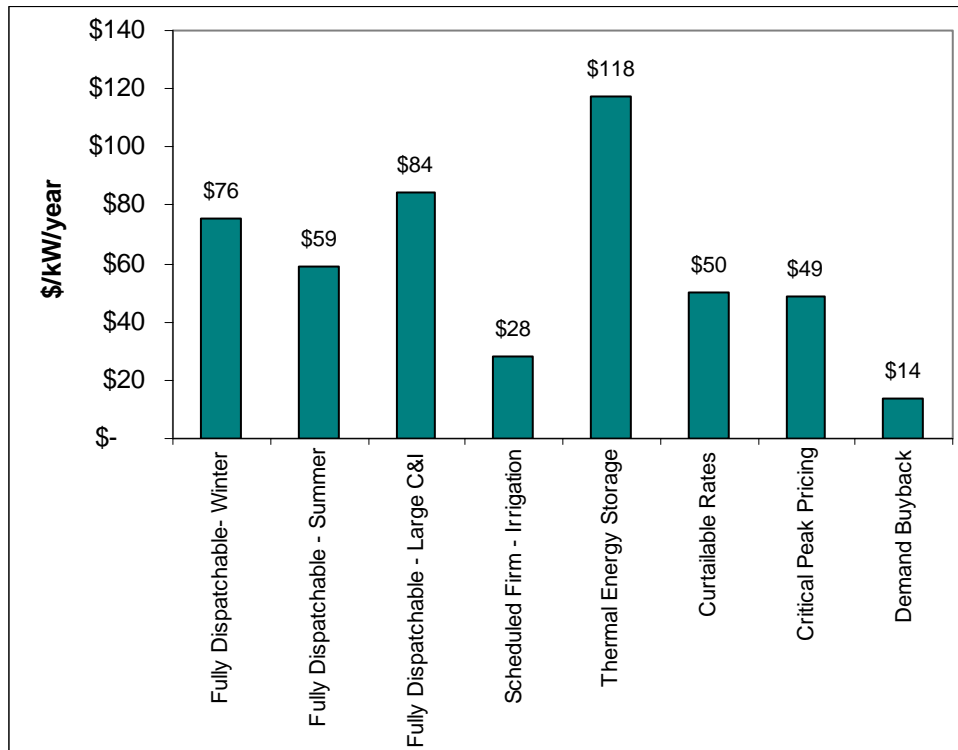


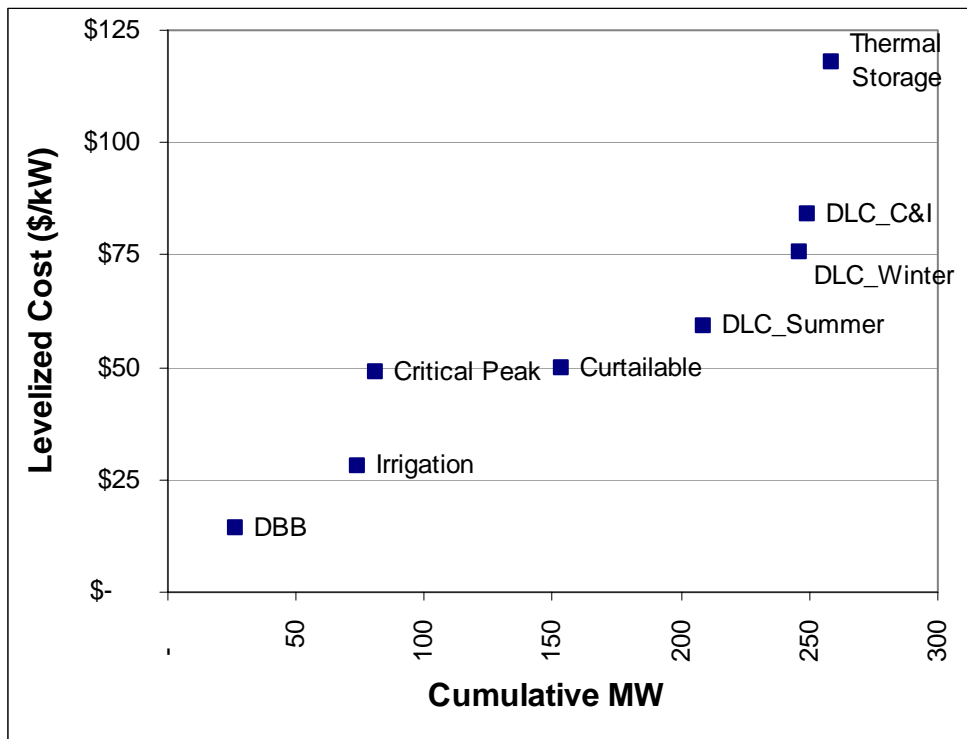
Figure 3 indicates that, with the exception of the irrigation program, per-unit costs tend to increase with the level of firmness of the load: the more reliable the load reduction, the more costly the program. Demand buyback, at \$14/kW/year, is expected to be the least expensive option. This program, although relatively inexpensive, provides possibly the least reliable load reduction among the eight program options.

Firm irrigation is the next lowest-cost resource at \$28/kW/year. Because reductions by this program are pre-determined and scheduled, it is an effective program for achieving firm seasonal load reductions. However, its value as a reliability option is limited because 100% capacity reductions are already incorporated into the utility’s planned resource capacity, and hence cannot be “called” to provide load relief during system emergencies. Critical peak pricing (\$49/kW/year) provides the ability to notify customers of curtailment events; national experience indicates the potential for reductions can be significant, but customer acceptance and response have generally been lower than expected. Curtailable rate programs (\$50/kW/year) may provide additional dependability due to contract requirements on customers and may serve as an effective option for reliability purposes. Owing mainly to hardware costs and incentives required of fully dispatchable resources, per-unit costs for the three direct load control programs exceed \$59/kW/year. Finally, thermal energy storage is expected to be the most costly option with a per-unit cost of \$118/kW/year.

The proxy supply curve for the eight resource options investigated in this study was constructed based on estimated achievable resource potential net of current programs and per-unit cost of each resource option. Figure 4 displays graphical presentation of the supply curve, which

represents the quantity of resources (cumulative MW) that can be achieved at or below the cost at any point. Cumulative MW is created by summing the achievable potential net of current programs along the horizontal axis sequentially, in the order of their levelized costs. For example, the irrigation program has 47 MW available, and its cost is second lowest. Therefore, its quantity is added to the 27 MW of DBB, showing that in total, 74 MW of resources are available at prices equal to or less than \$28/kW.

Figure 4. Cumulative Supply Curve, System



Resource Potential Scenarios

High and Low

For the purpose of IRP modeling, achievable potentials were estimated under three scenarios: base case, high, and low, corresponding with PacifiCorp’s projected on-peak market prices of \$40/MWh (low), \$60 (base) and \$100 (high). To account for the relationship between market prices (and incentives) and program potential, high scenarios generally assume aggressive marketing efforts and higher incentive levels and, therefore, higher program participation. The low scenario reflects a less aggressive marketing effort and relatively weak program participation. (See Sections IV and V for assumptions underlying the two scenarios.)

The high and low scenarios for the DBB and curtailment contract options were constructed based on load response elasticity estimates. As reported in the 2006 Department of Energy’s Report to Congress, commercial and industrial customers have typically exhibited an inelastic response to

prices (elasticity = 0.1) in load curtailment. This figure was used as a basis for the high and low program participation scenarios for the fully dispatchable large commercial and industrial and curtailable rates options. For the DBB program, a price elasticity of 1.45, estimated based on the 2000-2001 regional data on demand buyback programs, was used to develop the high and low scenarios. (See Section IV for a discussion of methodology and data.)

The results for the three scenarios are shown in Table 5. Generally, as the potential increases, so does the per-unit costs, due to higher incentives and marketing costs. Yet, in a few cases, such as critical peak pricing and fully-dispatchable commercial and industrial programs, per-unit costs are expected to fall from the low to the base case due to economies of scale; lower marginal per-unit costs result from the fact that fixed program costs are spread over a larger number of units.

Table 5. High, Base, and Low Costs and Quantities System

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Low								
Achievable Potential MW	19	80	1	76	7	30	1	9
Resource Costs (\$/kW/yr)	\$58	\$53	\$167	\$29	\$115	\$39	\$91	\$13
Base								
Achievable Potential MW	37	120	3	95	9	72	7	28
Resource Costs (\$/kW/yr)	\$76	\$59	\$84	\$28	\$118	\$50	\$49	\$14
High								
Achievable Potential MW	56	141	9	114	12	88	14	65
Resource Costs (\$/kW/yr)	\$84	\$72	\$102	\$37	\$119	\$86	\$45	\$18

Treatment of Metering Costs

The DR scenarios presented above include metering costs, where applicable (please see Section V for detailed assumptions). In the future, these costs may not be necessary if advanced metering technology is implemented in PacifiCorp’s territory. Therefore, this additional scenario excludes metering costs from the base estimates of per unit cost. Figure 5 below displays the new figures and Table 6 provides a comparison of the base (with metering) scenario and the alternative (without metering). The exclusion of meter costs makes little difference (less than \$1/kW/year) in all programs, except critical peak pricing where the reduction equals \$7 /kW/year.

Figure 5. Per Unit Resource Costs – Excluding Metering Costs

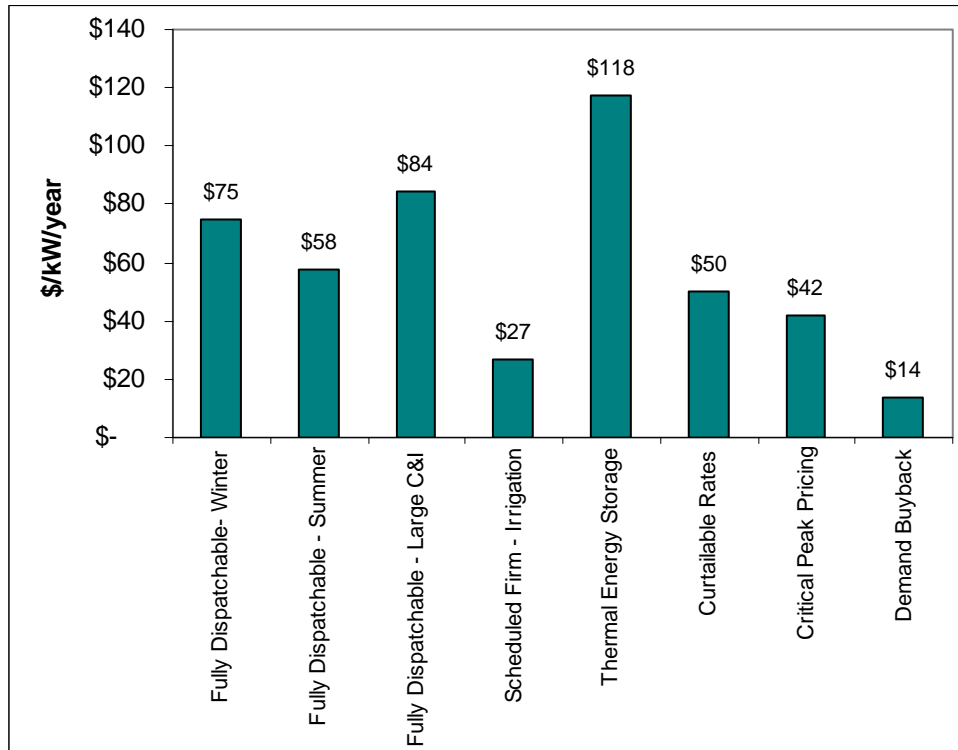


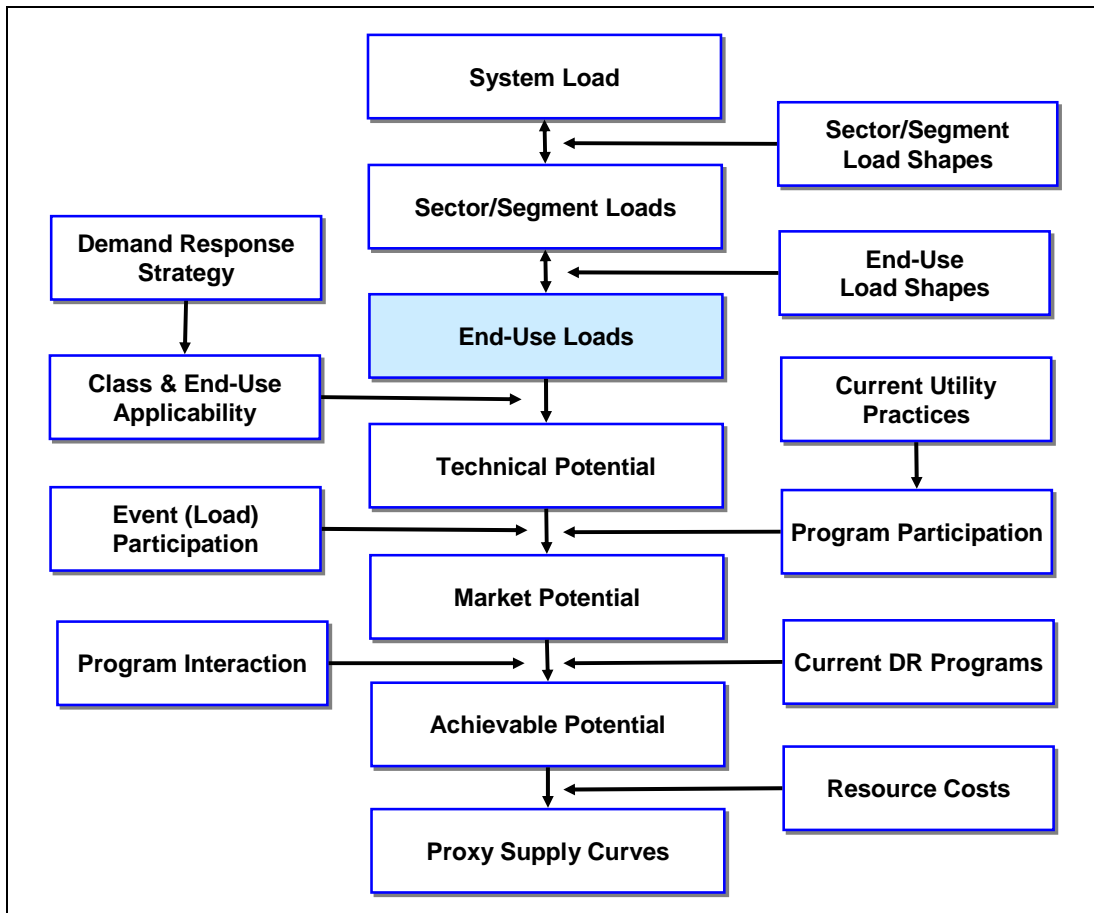
Table 6. Comparison of Costs with and without Metering Costs

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
With Meter Costs (\$/kW/year)	\$76	\$59	\$84	\$28	\$118	\$50	\$49	\$14
Without Meter Costs (\$/kW/year)	\$75	\$58	\$84	\$27	\$118	\$50	\$42	\$14

IV. Methodology and Data

The development of proxy supply curves requires both reasonable approximations of available quantities and reliable estimates of procurement costs for each DR resource. With respect to quantities, the overall approach in this project (see Figure 6) distinguishes between three definitions of DR resource potential that are widely used in utility resource planning: *technical*, *market*, and *achievable*. Load shapes for the PacifiCorp system, East/West regions, customer segments, and end use load shapes combine with sales data to produce hourly load profiles. For each DR strategy, technical potential is estimated by applying end use and sector applicability, while market potential additionally incorporates program and event participation. Achievable potential estimates also consider interactions among programs and current DR offerings at PacifiCorp. Finally, proxy supply curves show the relationship between achievable potential and the expected per-unit cost of each strategy.

Figure 6. Schematic Overview of Methodology



Data Requirements and Sources

Development of DR supply curves requires the compilation of a large and complex database on load data, end-use and appliance saturations, demand response impacts, and costs, gathered from multiple sources. To the greatest extent possible, this study relies on data available from PacifiCorp on loads, sales, end-use load profiles, and estimates of administrative costs. Secondary data sources were utilized for estimates of DR program impacts. Specific data elements and their respective sources are listed in Table 7.

Table 7. Data Elements and Sources

Data Element	Source – Various Years
Total Sales by Customer Class	PacifiCorp, 2005, Table A
Commercial Segmentation	PacifiCorp, 2005, Commercial Survey (by participants)
Hourly System and Regional Load Profiles	PacifiCorp, 2005
End-Use Shares and Load Shapes	EIA, Commercial Buildings Energy Consumption Survey (CBECS) EIA, Residential Energy Consumption Survey (RECS) Northwest Power Planning Council PacifiCorp PGE Quantec Load Shape Library
Existing PacifiCorp Demand Response Programs	PacifiCorp studies, various years
Demand Response Impact Estimates	PacifiCorp, California Energy Commission, Peak Load Management Alliance (PLMA), Edison Electric Institute (EEI), Lawrence Berkeley National Laboratories (LBNL), Various RTO and Utility Reports, Department of Energy
Demand Response Program Costs	PacifiCorp, Other Utilities, Regional Transmission Organizations

Methodology for Estimating Technical Potential

Within the context of demand response, technical potential assumes that all applicable end-use loads, in all customer sectors, are at least partially available for curtailment, excepting those customer segments (e.g., hospitals) and end-uses (e.g., restaurant cooking loads) that clearly do not lend themselves to curtailment.

Demand response options are not equally applicable to or effective in all segments of the electricity consumer market, and their impacts tend to be end-use specific. In recognition of this fact, this methodology employs a “bottom-up” approach, which involves first breaking down system loads for each of PacifiCorp’s two control areas into sectors, market segments within each sector, and applicable end uses within each market segment. Demand response potentials are estimated at the end-use level and then aggregated to sector and system levels. This approach is implemented in four steps as follows.

- 1. Define customer sectors, market segments, and applicable end-uses.** The first step in the process involves defining appropriate sectors and market segments within each sector. Given the available data, this study includes four customer classes (residential, commercial, industrial, and irrigation), the eleven commercial segments defined in

Commercial Building Energy Consumption Survey (Education, Food Stores, Hospitals, Hotels/Motels, Other Health, Offices, Public Assembly, Restaurants, Retail, Warehouses, and Miscellaneous), and total industrial loads.

2. **Create sector and segment load profiles.** Using available local hourly load profiles, service area sales are used to generate sector- and segment-specific load shapes. Figure 7 displays the load duration curves for East, West and System overall, and Figure 8 shows the typical daily system load profiles. Figure 9 exhibits sector load shapes; the “System” shown is the actual load and “Total Sector” is the sum of load by sector. The difference between these lines are due to loads that are not amenable to demand response, such as traffic and street lighting, and loads not directly attributable to end use load profiles.

Figure 7: PacifiCorp Load Duration Curve, 2005

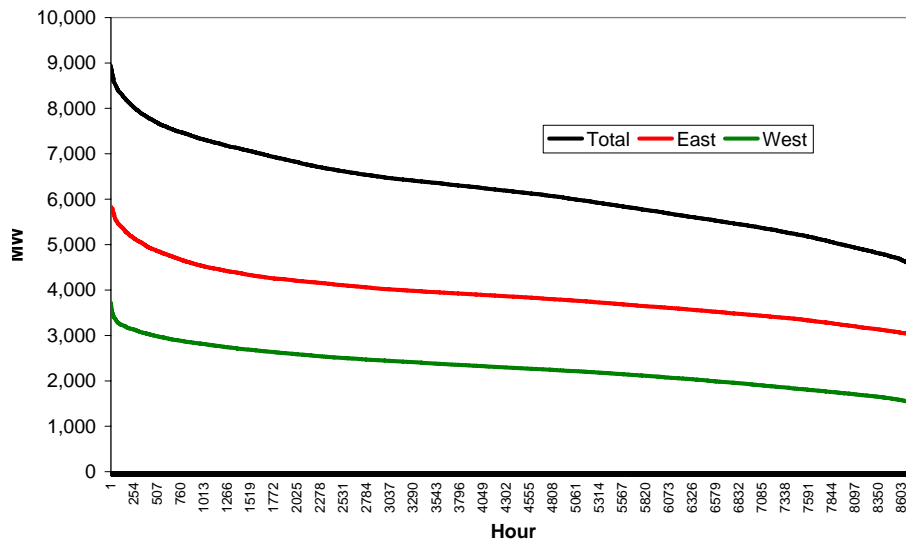


Figure 8: Typical Daily (Week-Day) Seasonal Load Profiles by System and Control Area

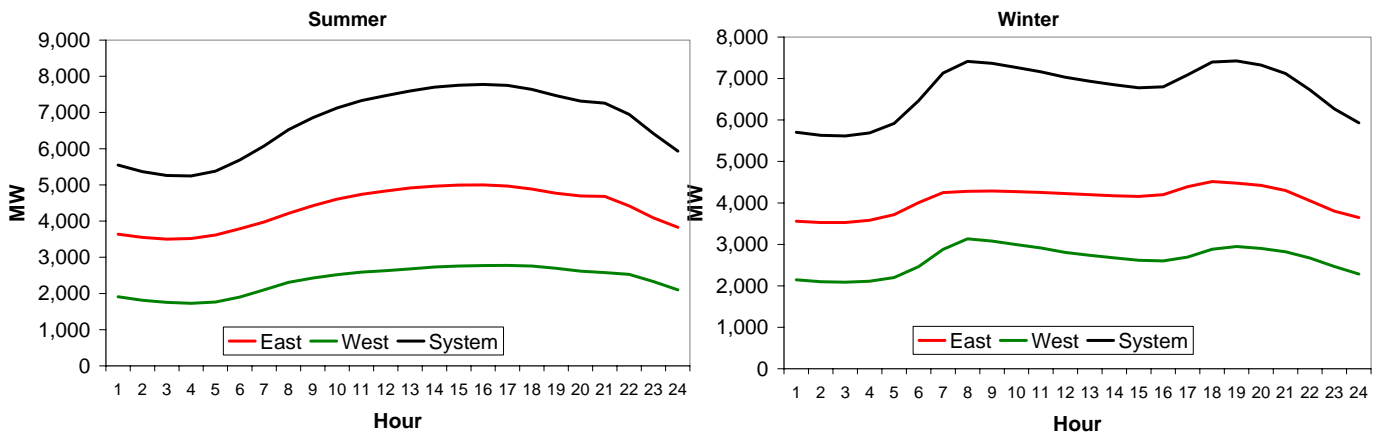
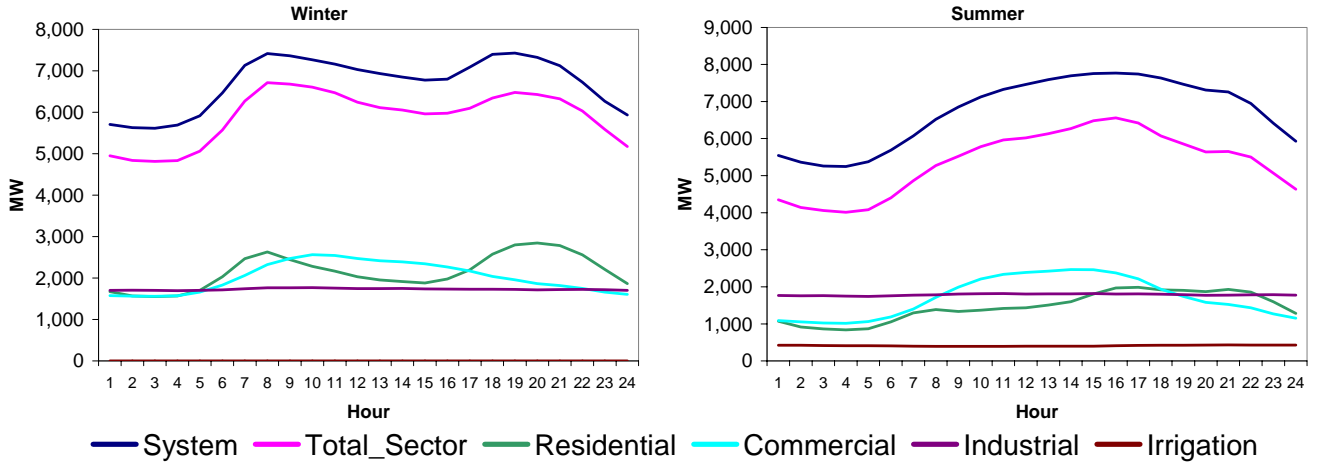


Figure 9: Typical Daily (Week-Day) System Load Profiles by Sector



3. *Develop sector- and segment-specific typical peak day load profiles for each end use.* “Typical” daily profiles are developed for each end-use within various market segments. Contributions to system peak for each end-use are estimated based on end-use shares available from PacifiCorp or regional estimates, available through EIA energy use surveys. Figure 10 and Figure 11 display the end-use contributions, summarized across sectors, to system load.

Figure 10: End-Use Contributions to System Load- Summer

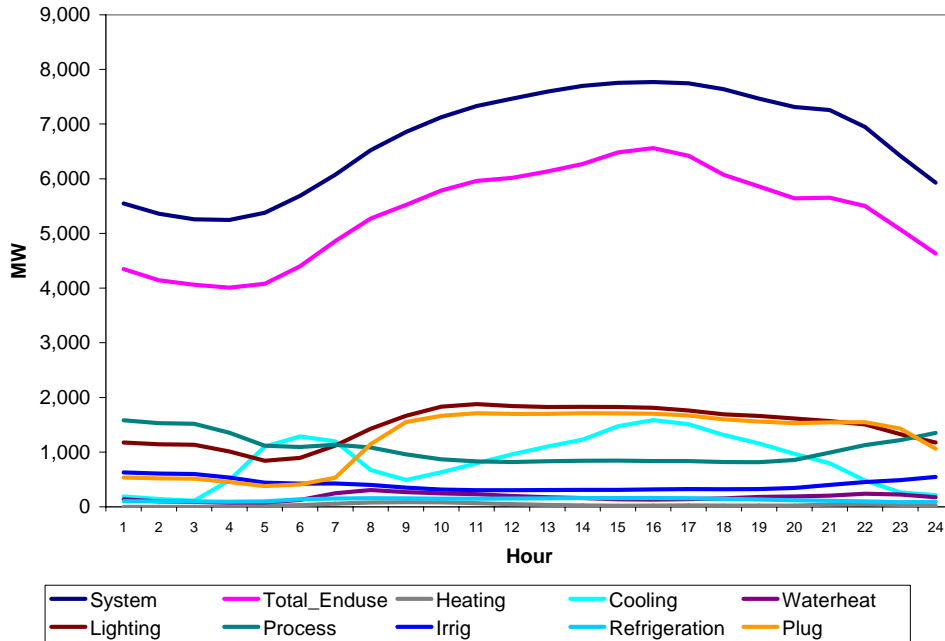
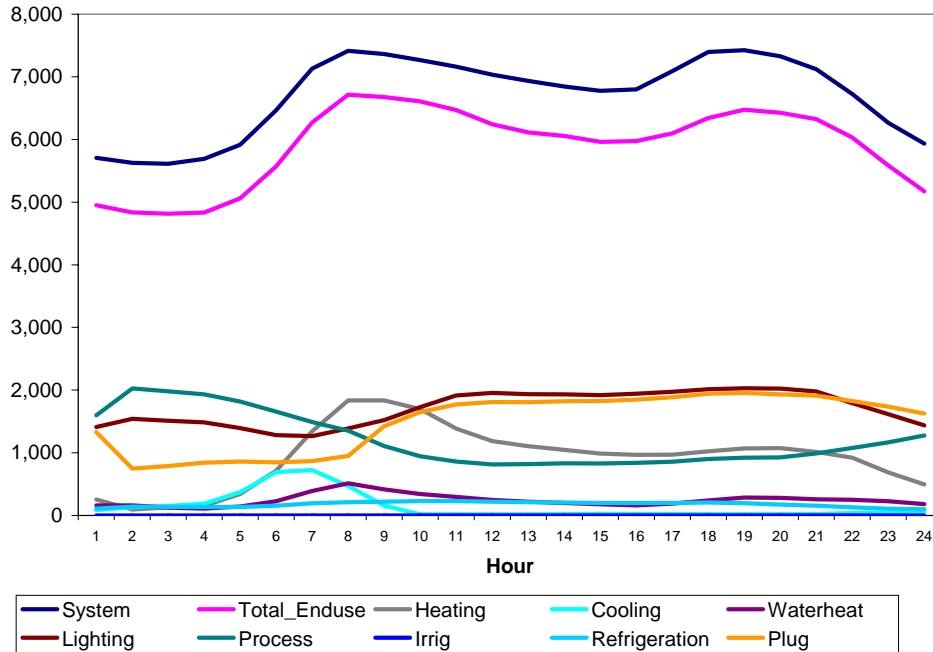


Figure 11: End-Use Contributions to System Load- Winter



4. **Estimate technical potential.** Technical potential for each demand response strategy is assumed to be a function of customer eligibility in each class and the expected impact of the strategy on the targeted end-uses. Analytically, technical potential (TP) for demand-response strategy s is calculated as the sum of impacts at the end-use level (e), generated in customer sector (c), by the strategy (s), that is:

$$TP_s = \sum TP_{sce}$$

and

$$TP_{sce} = LE_{cs} \times LI_{se}$$

where,

- LE_{cs} (load eligibility) represents the percent of customer class loads that are eligible for strategy s
- LI_{se} (load impact) is percent reduction in end-use load e resulting from strategy s

Load eligibility (LE_{cs}) thresholds are established by calculating the percent of load by customer class and market segment that meet load criteria for each strategy. Table 8 outlines the portion of load that is eligible for program strategies. (Section V provides detailed program-specific assumptions.)

Estimates of maximum load impacts, resulting from various demand response strategies (LI_{se}), are derived from the commercial and industrial Enhanced Automation Study sponsored by the California Energy Commission, studies by Lawrence Berkeley National Laboratories

(e.g., Goldman, 2004), and the experiences of PacifiCorp and other utilities with similar DR programs. Table 9 outlines these inputs; detailed assumptions are found in the following section.

Table 8: Eligibility by Sector and Program

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	100%	100%	---	---	---	-	100%	-
Education	---	---	19%	---	---	50%	100%	50%
Food Stores	---	---	27%	---	---	70%	100%	70%
Hospitals	---	---	---	---	---	-	-	-
Hotels/Motels	---	20%	5%	---	20%	12%	100%	12%
Other Health	---	7%	23%	---	7%	60%	-	60%
Miscellaneous	---	---	---	---	---	-	-	-
Offices	---	10%	19%	---	10%	50%	100%	50%
Assembly	---	10%	8%	---	10%	20%	-	20%
Restaurants	---	50%	---	---	50%	-	-	-
Retail	---	12%	---	---	12%	-	-	-
Warehouses	---	13%	15%	---	13%	40%	-	40%
Industrial	---	---	30%	---	---	80%	100%	80%
Irrigation	---	---	19%	100%	---	50%	-	-
Eligibility Criteria	Residential	Residential and Small Commercial (<30 kW)	Large C&I - >250 kW with EMS	Irrigation only	Small Commercial	Large C&I - >250 kW	No Load Threshold	Large C&I - >250 kW

Table 9: Technical Load Impacts

Program Name/Sector	Fully Dispatchable				Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter		Summer	Large C&I					
End Use	Space Htg	Hot Water	Cooling	Total	Process	Cooling	Total	Total	Total
Residential	90%	90%	90%	---	---	---	---	25%	---
Education	---	---	---	22%	---	---	22%	25%	22%
Food Stores	---	---	---	20%	---	---	20%	25%	20%
Hospitals	---	---	---	---	---	---	---	---	---
Hotels/Motels	---	---	90%	20%	---	90%	20%	25%	20%
Other Health	---	---	90%	8%	---	90%	8%	---	8%
Miscellaneous	---	---	---	---	---	---	---	---	---
Offices	---	---	90%	32%	---	90%	32%	25%	32%
Assembly	---	---	90%	20%	---	90%	20%	---	20%
Restaurants	---	---	90%	---	---	90%	---	---	---
Retail	---	---	90%	---	---	90%	---	---	---
Warehouses	---	---	90%	30%	---	90%	30%	---	30%
Industrial	---	---	---	30%	---	---	30%	25%	30%
Irrigation	---	---	---	30%	90%	---	30%	---	30%

Methodology for Estimating Market Potential

Market potential is the subset of technical potential that may reasonably be implemented, taking into account the customers’ ability and willingness to participate in load reduction programs, subject to their unique business priorities, operating requirements, and economic (price) considerations. Market levels of potential are derived by adjusting technical potentials by two factors: expected rates of *program* and *event* participation. Market potential (MP) is calculated as the product of technical potential, sector program participation rates (PP_c), and expected event participation (EP_c) rates:

$$MP_s = TP_{sc} \times PP_c \times EP_c$$

Rates of program and event participation are estimated based on the recent experiences of PacifiCorp and other utilities, as well as those of Regional Transmission Organizations (RTOs) that have offered similar programs. Table 10 outlines the estimates of program and event participation; referenced assumptions are found Section V.

Table 10: Program and Event Participation Inputs

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Program Participation	10%	20%*	3%	50%	20%	25%	3%	35%
Event Participation	100%	100%	90%	50%	100%	90%	90%	13%

* Represents residential sector; commercial sector is assumed to be 5%

Utility customers’ willingness to participate in DR programs (or “market potential”) is itself a function of price and non-price factors. Non-price factors generally depend on specific operational constraints that may impede participation in DR. These are generally difficult to quantify and may only be determined through rigorous market studies.

Price-induced effects, particularly for market-based DR strategies, can, however, be estimated explicitly by calculating price elasticity of load response, based on empirical data, using the following general formulation of price elasticity:

$$\text{Log}N(MW) = \alpha + \beta \text{LOG}(P),$$

where MW is the quantity of demand reduction commitment during each curtailment event and P represents the offer prices (incentives) from the utility.

Since the equation is specified in logarithmic form, β is a direct measure of elasticity, indicating percent change in load commitment that may be expected to result from a one percent change in incentives.

To estimate the parameters of the above model, data were collected on the 2000-2001 experience of four major utilities in the Northwest (PacifiCorp, PSE, PGE, and Avista) on their demand buyback programs. The estimated parameters of the model are shown below.

$$\text{LogN}(MW) = -0.5 + 1.45 (3.0) \text{LogN}(P)$$

The calibration of the demand model resulted in a price coefficient of 1.45 with a t-statistic of 3.0, indicating that the estimated coefficient is statistically significant at the 95% level of significance or better. The estimated parameter for the price variable shows that for every one percent change in price, load response is expected to change by 1.45%, indicating a moderately elastic response. The statistical parameters of the estimated model are shown in Table 11, below.

Table 11. Estimation Results of the Elasticity Model

Variable	Estimated Parameter	t-Statistic
Intercept (α)	-0.5	
LogN (Price)	1.45	3.0
Number of Observations: 13		

$R^2 = 0.65$

The elasticity estimate obtained from the data is higher than expected. There have not, however, been any other studies of response elasticity for demand buyback or demand bidding programs. Additionally, slight changes in the specification of the above quantity/price relationship, introduced by using alternative data frequency levels, such as daily or monthly, are likely to alter the parameter estimates. For example, daily, event-by-event data, available from Puget Sound Energy for 2000-2001, resulted in a significantly lower elasticity of 0.45. Unfortunately, event-by-event data were not available for all four utilities. Such data, we expect, would likely have produced a more robust and reliable estimate of price elasticity for demand buyback programs.

Development of Cost Estimates

Demand response strategies vary significantly with respect to both type and level of costs. Applicable resource acquisition costs for DR generally fall into two categories: 1) fixed direct expenses such as infrastructure, administration, and data acquisition; and 2) variable costs (i.e., incentive payments to participants). For this project, cost estimates are based on the experiences of PacifiCorp and other utilities, as well as RTOs offering various DR programs.

Fixed Costs. Fixed costs vary significantly across various DR resource acquisition programs and depend, to a large extent, on program design. For example, implementation of some market-based programs, such as demand buyback, may require up-front investments in communication and data acquisition infrastructures, while tariff-based programs may be implemented at a relatively low cost to the utility.

Variable Costs. Estimation and treatment of variable costs, particularly in the case of market-based programs poses a much greater challenge in determining the price component of the supply curve as, clearly, these will have a direct effect on the quantity of resources that are available. As described above, elasticity estimates were used to account for these impacts.

Table 12 outlines the development (up-front investment) and annual costs for the three categories of cost inputs: per-kW/year, per-customer, and program administration. Incentive payments for large commercial and industrial customers are often paid on a per-kW basis. On a per-customer basis, development costs typically include control hardware, installation, and marketing costs; annual costs include maintenance and incentives. Program costs were assumed to be relatively consistent across all programs - \$300,000 to begin a new program, \$150,000 to expand existing programs¹⁰; \$100,000 in ongoing administrative cost.¹¹

Table 12: Cost Inputs

Cost Type/ Frequency	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
per kW-year								
Development	---	---	---	---	---	---	---	---
Annual	---	---	\$48	\$10	\$105	\$48	---	\$10
per Customer-year (including meter costs)								
Development	\$320	\$320	\$1,200	\$700	---	\$1,200	\$500	\$700
Annual	\$112	\$55	---	\$1,000	---	---	\$50	---
Program								
Development	\$300,000	\$150,000	\$300,000	\$150,000	\$300,000	\$300,000	\$300,000	\$150,000
Annual	\$100,000	\$100,000	\$100,000	\$600,000	\$100,000	\$100,000	\$100,000	\$100,000

These costs are allocated to each year of the planning horizon, based on:

$$Costs_{sy} = \$Pgm_{dy1} + \$Pgm_a + (\$kW_a \times kW_y) + (\$Customer_d \times Part_{y-y0}) + (\$Customer_a \times Part_y)$$

¹⁰ PacifiCorp Energy Exchange (2001) spent over \$200,000 in initial costs. TOU (2001) had initial costs of \$341,000, including load research.

¹¹ Energy Exchange (2005) spends \$72,000 annually in external vendor costs (not including PacifiCorp administrative costs), Idaho Irrigation Pilot (2005) spent \$55,000 in program management, TOU had ongoing costs of \$155,000 (2002) and \$110,000 (2003).

Where,

- $Costs_{sy}$ are the costs for a program strategy s in year y ,
- $\$Pgm_{dy1}$ are the program development costs in year 1 only
- $\$Pgm_a$ are the annual program costs
- $\$kW_a$ are the annual costs on a per kW basis (Table 12)
- kW_y is the amount of kW potential in year y . This study uses a three-year ramping, such that one-third of the achievable potential, shown in Table 4, is added in each of the first three program years. The quantity in subsequent years increases at the same rate as sales.
- $\$Customer_d$ are per-customer development costs
- $Part_{y-y0}$ is the number of new participants in the program in year y
- $\$Customer_a$ is the annual cost per customer
- $Part_y$ is the number of total participants in the program, as a function of $PartkW$, which is the kW impact per customer, as shown in Table 13 (program-level assumptions found in Section V).

$$Part_y = \frac{kW_y}{Part_{kW}}$$

Table 13: Load Impact per Customer (kW)

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	2.0	1.5	---	---	---	---	2	---
Education	---	---	124	---	---	124	21	124
Food Stores	---	---	134	---	---	134	22	134
Hospitals	---	---	---	---	---	---	-	---
Hotels/Motels	---	2.0	104	---	---	104	10	104
Other Health	---	2.0	82	---	---	82	---	82
Miscellaneous	---	---	---	---	---	---	---	---
Offices	---	2.0	221	---	---	221	7	221
Assembly	---	2.0	230	---	---	230	---	230
Restaurants	---	2.0	---	---	---	---	---	---
Retail	---	2.0	---	---	---	---	---	---
Warehouses	---	2.0	173	---	---	173	---	173
Industrial	---	---	531	---	---	531	53	531
Irrigation	---	---	---	90	---	---	---	---

Resource Interaction Estimates

The final step in supply curve development is to estimate the amount of market potential that is available for each program in the portfolio. Table 14 outlines the percent of market potential that is considered available, given the ranking of programs by levelized cost with consideration given to reliability. For example, 100% of demand buyback and scheduled firm irrigation is considered achievable. Although critical peak pricing is ranked next in levelized cost, it is another non-firm resource, so it becomes tertiary to curtailable rates. Curtailable rates and dispatchable large C&I compete for the same target market as DBB, therefore only 50% of their market potential will be available. The summer DLC program is the least expensive residential and small commercial control program. Therefore 100% of this program is available. Since the TES also targets the cooling loads (cool storage) as a secondary option, half of the TES potentials are assumed to be available.

Table 14: Interaction (Percent of Market Potential Available)

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	50%	100%	---	---	---	---	20%	---
Education	---	---	50%	---	---	50%	20%	100%
Food Stores	---	---	50%	---	---	50%	20%	100%
Hospitals	---	---	---	---	---	---	---	---
Hotels/Motels	---	100%	50%	---	50%	50%	20%	100%
Other Health	---	100%	50%	---	50%	50%	---	100%
Miscellaneous	---	---	---	---	---	---	---	---
Offices	---	100%	50%	---	50%	50%	20%	100%
Assembly	---	100%	50%	---	50%	50%	---	100%
Restaurants	---	100%	---	---	50%	---	---	---
Retail	---	100%	---	---	50%	---	---	---
Warehouses	---	100%	50%	---	50%	50%	---	100%
Industrial	---	---	50%	---	---	50%	20%	100%
Irrigation	---	---	50%	100%	---	50%	---	---

V. Detailed Program Assumptions

Table 15. Fully Dispatchable – Winter

Programs Researched	Portland General Electric Space and Water Heating Direct Load Control Program; Pennsylvania, New Jersey, Maryland ISO water heating; Florida Power & Light Residential On Call program; Puget Sound Energy Home Comfort Control Thermostat; Hawaiian Electric Residential Hot Water; Wisconsin Public Services DLC
Load Basis	Average of top 87 winter hours
Basis for Cost Calculations	Development: Customer - \$300 for control equipment and labor, \$200 for meter and installation labor (PGE – Quantec 2003) but installed for only 10% of participants, \$300,000 for program development; Annual: \$30 in maintenance, \$9 (1.5/month for 6 months) in communications, \$72 (\$12/month for 6 months - both water heating and space) in incentives, and \$100,000 annual program administration.
High/Low Cost Notes	High assumes incentives are increased (\$15/month - \$90), low is half incentive (\$6/mth - \$36). Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Less than complete technical ability to cycle different technologies (90%) and 50% cycling strategy; therefore 45%
Eligible Load (%)	Residential space heating and water heating
Program Participation (%)	High is based on 20% participation of FPL On Call program, base (10%) closer to Duke program of 13% (Duke – Quantec 2005), and low (5%) represents low program participation (DOE - 2006)
Event Participation (%)	100%
Current Program (kW)	NA
Per-Customer Impacts (kW)	2kW estimate per participant based (PSE, Quantec 2003) - includes cycling strategy
Hours Per Month	3 hours in January; 84 hours in December (based on the distribution of the PacifiCorp 2005 system profile)

Table 16. Fully Dispatchable – Summer

Programs Researched	Florida Power & Light Residential On Call & Business On Call; SCE Large Business Summer Discount Plan; Wisconsin Public Services; Duke Residential AC Program, PacifiCorp and MidAmerican
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Customer - \$300 for control equipment and labor, \$200 for meter and installation labor (PGE – Quantec 2003) but installed for only 10% of participants, \$300,000 for program development; Annual: \$30 in maintenance, \$4.5 (1.5/month for 3 months) in communications, incentives - \$20 (3 months at \$7/month - PSE pays \$6, Duke \$8, PAC \$7), and \$100,000 annual program administration
High/Low Cost Notes	High assumes incentives are doubled (\$40), low is half incentive (\$10). Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Less than complete technical ability to cycle different technologies (90%) and 50% cycling strategy; therefore 45%
Eligible Load (%)	Cooling load for residential and portion of commercial load that is less than 30 kW (PacifiCorp - Quantec 2003)
Program Participation (%)	Assumes 20% residential and 5% small commercial (FP&L - 13% small C&I participation, 19% residential, PAC Utah Cool Keeper 27% residential and ~0% commercial), high assumes that 5% more program participation is possible, low assumes 5% less
Event Participation (%)	100%
Current Program (kW)	65 MW of load reduction in Utah Cool Keeper Program on Dispatch mode
Per-Customer Impacts (kW)	Impact: Cooling - 1.5 kW for residential, 2.0 kW for small com, DOE 2006, Quantec 2003
Hours Per Month	June 8, July 54; August 32 – adjusts 2005 System load to account for experience in program dispatch by Cool Keeper

Table 17. Fully Dispatchable – Large C&I

Programs Researched	Florida Light & Power C&I On Call; Hawaiian Electric Large Commercial; Wisconsin Public Services DLC; Southern California Edison Large Business Summer Discount Plan
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Per customer of \$500 for targeted marketing and \$700 for meter (Duke – Quantec 2005); \$300,000 for program development, \$100,000 annual program administration. Per kW costs assume \$8/month for 3 months (double the incentive as curtailable rates but for fewer months)
High/Low Cost Notes	High incentive is \$14/month and low is \$6/month (again, double curtailable rates incentive; see curtailable rates for references) Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of cooling load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003) and assuming only 38% with EMS systems (CBSA 05)
Program Participation (%)	Participation - Florida Power And Light C&I On Call has less than 1% of all customers. Because our figures already account for those not eligible, we have assumed 3% base, 8% high, and 1% low.
Event Participation (%)	90%
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	June 8, July 54; August 32 - adjusts 2005 System load to account for experience in program dispatch by Cool Keeper, assuming that system decisions to curtail residential customers would be similar for C&I customers

Table 18. Scheduled Firm – Irrigation

Programs Researched	BPA Irrigation, Idaho Power, PacifiCorp
Load Basis	Average of entire summer on-peak period
Basis for Cost Calculations	Development: \$700 installed cost of advanced metering technologies; Idaho IRR: Annual: \$10 per kW (\$8.5 in 2005), \$300,000 for program development, \$100,000 annual program administration. Also includes \$500K of additional expenditures committed in 2005 for ongoing programs by PacifiCorp.
High/Low Cost Notes	High cost doubles incentive; low assumes the same, Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Less than complete technical ability to schedule reductions on all load (e.g., lift stations)
Eligible Load (%)	Irrigation sector
Program Participation (%)	Program participation of 50% (2005 Idaho IRR - 100 MW signed up of 200 MW load) is assumed to be base. High and low has relatively tight band +/-5%.
Event Participation (%)	50% event participation assumes participants sign up only for 2 out of 4 days (similar to PacifiCorp Idaho program)
Current Program (kW)	48 MW from Idaho program
Per-Customer Impacts (kW)	Idaho reduction of 100 kW per customer reduced to 90 to account for smaller irrigators in other regions
Interaction	100% taken due to relatively inexpensive cost and lack of competition with other programs.
Variable Cost \$/MWh	NA
Hours Per Month	June – August 96 hours per month, September 48 hours per month (4 days per week, 6 hours per day)

Table 19. Thermal Energy Storage

Programs Researched	Based on RFP response to PacifiCorp, summarized for Quantec in "TES Overview"
Load Basis	Average of entire summer on-peak period
Basis for Cost Calculations	Costs from "TES Overview" sent to Quantec on June 2, 2006 using per-kW costs by external vendor, \$300,000 for program development, \$100,000 annual program administration
High/Low Cost Notes	Incentives remain constant, Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Less than complete technical ability to use this technology (90%) on cooling load
Eligible Load (%)	Using portion of commercial cooling load that is less than 30 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	20% program participation, with +/- 5% for high and low participation
Event Participation (%)	100%
Current Program (kW)	NA
Per-Customer Impacts (kW)	NA
Hours Per Month	240 – April, 186 – May, 180 – June, 186 – July, 186 – August, 180 – September, 279 October

Table 20. Curtailable Rates

Programs Researched	Duke Interruptible Power Service; Georgia Power (Southern) Demand Plus Energy Credit; Duke Curtailable Service Pilot; Dominion Virginia Power Curtailable Service; MidAmerican; ConEd Interruptible/Curtailment Service, Southern California Edison C&I Base Interruptible Program, Wisconsin
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Per Customer of \$500 for marketing and \$700 for meter (Duke - Quantec, 05); \$300,000 for new program development, \$100,000 annual program administration, Base incentive of \$48 (\$4/kWMonth) (Pacific Gas and Electric pays \$3-\$7/kWMonth, Southern California Edison pays \$7/kWMonth, Wisconsin Power and Light pays \$3.3/kWMonth, MidAmerican pays \$3.3, Duke Power pays \$3.5/kW-Month).
High/Low Cost Notes	Base incentive of \$48 (\$4/kWMonth) is increased by 50% in high case. Low assumes same incentive as base (\$42). Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	National participation ranges from slightly greater than 0% (ISO NE) of customers to 30%, (NYISO 29%, Duke 14%). Base assumes 25% (due to load eligibility already accounted for), 5% more for high case and 12.5% less for low case.
Event Participation (%)	Event Participation reflects compliance rate (Duke - 90% + compliance, CEC – 90% + compliance Goldman (2002))
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 69; August 18 (based on the distribution of the PacifiCorp 2005 system profile)

Table 21. Critical Peak Pricing

Programs Researched	Gulf Power GoodCents Select; Pacific Gas and Electric Critical Peak Pricing; Southern California Edison Critical Peak Pricing; San Diego Gas and Electric Critical Peak Pricing
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Customer: \$500 for advanced metering technologies; Program - \$300,000 for new program development; Annual: Customer - \$20 for meter reading, extra mailing, and messaging (PSE – Quantec (2004)), \$30 to account for the rate and energy benefits to the customer (Quantec PacifiCorp TOU (2005)) \$100,000 annual program administration
High/Low Cost Notes	Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Range of impacts from high 41% (Gulf Power super peak) to 18% (Piette, 2006), therefore assume low-mid-point of 25%, (other relevant references – McAuliffe (2004) DOE 2006)
Eligible Load (%)	Eligibility- all customers assumed to be eligible except those deemed unable to respond (based on sectors reported in Quantum (2004))
Program Participation (%)	Current programs in nation have very low participation (reviewed seven programs McAuliffe (2004) and Gulf Power with maximum of 3% - PG&E commercial program) - base is 3%, low is 0.5% and high is 5.5%
Event Participation (%)	Event participation assumed to be less than all - i.e., 90%
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 69; August 18 (based on the distribution of the PacifiCorp 2005 system profile)

Table 22. Demand Buyback

Programs Researched	Pacific Gas and Electric Demand Buyback (Commercial and Industrial); Southern California Edison Demand Buyback (Commercial and Industrial); San Diego Gas and Electric Demand Buyback; New York ISO Day Ahead Demand Response, PacifiCorp
Load Basis	Average of top 175 summer hours
Basis for Cost Calculations	Development: \$700 for advanced meter; Program development cost of \$150,000 for expansion; \$100,000 annually for program administration. Incentive of \$10/kW is consistent with 2005 PacifiCorp Integrated Resource Plan base prices of \$60/MWh
High/Low Cost Notes	High and low incentive levels are consistent with 2005 PacifiCorp Integrated Resource Plan base prices of \$40/MWh (low) and \$100/MWh (high). Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	Range of program participation is from 0-6% (various California utilities – Quantum (2004)) to 17-25% (PJM/NYISO – Goldman (2004)). This study uses 35% to account for the eligibility correction for those >250 kW. High is 30%, low is 5%
Event Participation (%)	Event participation calculated from 2001 Northwest demand bidding experience
Current Program (kW)	1 MW of participation (165 MWh over 15 events, 10 hours per event)
Per-Customer Impacts (kW)	Per-customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 129; August 46 (based on the distribution of the PacifiCorp 2005 system profile)

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Appendix A: East Region Results

Table 23: Technical Potential (MW), East

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	143	---	---	377	392	368
Commercial	---	35	30	---	59	79	134	76
Irrigation	---	---	---	254	---	---	---	---
Residential	163	318	---	---	---	---	342	---
Total	163	353	173	254	59	455	868	444
<i>% of East Peak</i>	<i>3%</i>	<i>7%</i>	<i>3%</i>	<i>5%</i>	<i>1%</i>	<i>9%</i>	<i>17%</i>	<i>9%</i>

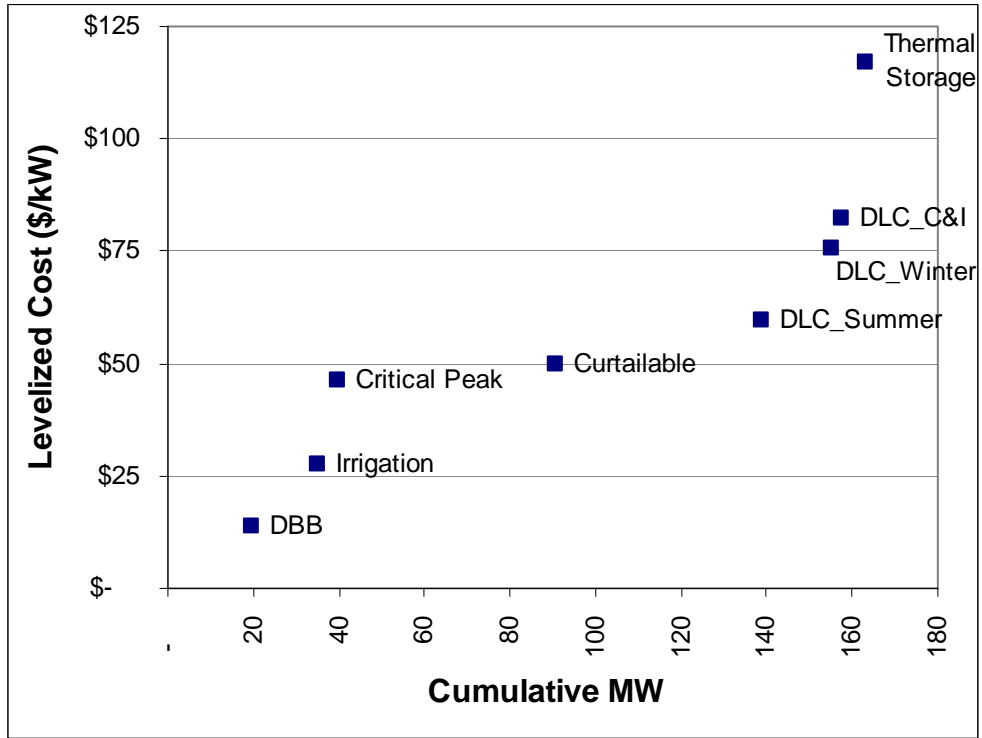
Table 24: Market Potential (MW), East

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	4	---	---	85	11	16
Commercial	---	2	1	---	12	18	4	3
Irrigation	---	---	---	63	---	---	---	---
Residential	33	111	---	---	---	---	9	---
Total	33	113	5	63	12	102	23	19
<i>% of East Peak</i>	<i>0.7%</i>	<i>2.3%</i>	<i>0.1%</i>	<i>1.3%</i>	<i>0.2%</i>	<i>2.0%</i>	<i>0.5%</i>	<i>0.4%</i>

Table 25. Achievable Potential (MW) and Costs, East

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Resource Costs (\$/kW/yr)	\$76	\$59	\$82	\$28	\$117	\$50	\$46	\$14	---
Achievable Potential	16	113	2	63	6	51	5	19	276
Potential Net of Current Programs	16	48	2	15	6	51	5	19	163

Figure 12: Cumulative Supply Curve, East



Appendix B: West Region Results

Table 26. Technical Potential, West

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	50	---	---	133	138	132
Commercial	---	20	21	---	35	54	98	54
Irrigation	---	---	---	128	---	---	---	---
Residential	210	33	---	---	---	---	275	---
Total	210	54	71	128	35	187	512	185
% of West Peak	7%	2%	2%	4%	1%	6%	16%	6%

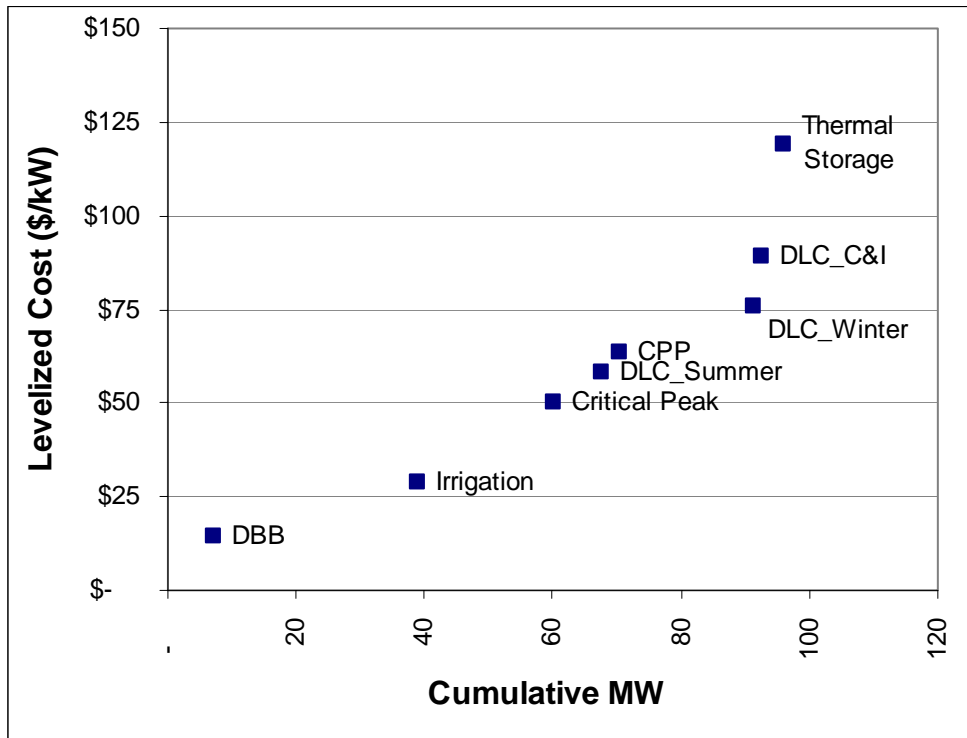
Table 27. Market Potential, West

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	1	---	---	30	4	6
Commercial	---	1	1	---	7	12	3	2
Irrigation	---	---	---	32	---	---	---	---
Residential	42	7	---	---	---	---	7	---
Total	42	8	2	32	7	42	14	8
% of West Peak	1.3%	0.2%	0.1%	1.0%	0.2%	1.3%	0.4%	0.3%

Table 28. Achievable Potential (MW) and Costs, West

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Resource Costs (\$/kW/yr)	\$76	\$58	\$89	\$29	\$119	\$50	\$63	\$15	---
Achievable Potential	21	8	1	32	3	21	3	8	97
Potential Net of Current Programs	21	8	1	32	3	21	3	7	96

Figure 13: Supply Curve, West



Appendix C: Data Provided to IRP

Figure 14: East Region, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable- Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	51	5	19
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	76	59	82	28	117	50	46	14
Low								
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	22	1	6
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	58	53	159	29	115	38	95	13
High								
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	63	9	46
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	84	73	101	37	118	86	42	18
Hours Available by Month								
January	-	-	-	-	-	-	-	-
February	3	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 15: West Region, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable- Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Start Year	21	8	1	32	3	21	3	8
Base								
Total Achievable Potential --Maximum (MW)	-	-	-	-	-	-	-	1
Currently Under Contract	76	58	89	29	119	50	63	15
Resource Costs (\$/kW/yr)								
Low								
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	9	0	3
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 58	\$ 61	\$ 185	\$ 30	\$ 116	\$ 39	\$ 144	\$ 14
High								
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	26	5	19
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 84	\$ 70	\$ 104	\$ 37	\$ 121	\$ 87	\$ 56	\$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 16: System, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable- Large C&I	Scheduled Firm- Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Start Year	2	2	4	6	6	4	4	10
Base								
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	72	7	28
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 76	\$ 59	\$ 84	\$ 28	\$ 118	\$ 50	\$ 49	\$ 14
Low								
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	30	1	9
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 58	\$ 53	\$ 167	\$ 29	\$ 115	\$ 39	\$ 91	\$ 13
High								
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	88	14	65
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 84	\$ 72	\$ 102	\$ 37	\$ 119	\$ 86	\$ 45	\$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 17: East Region, No DBB

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable- Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	102	5
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 76	\$ 59	\$ 82	\$ 28	\$ 117	\$ 49	\$ 46
Low							
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	43	1
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 58	\$ 53	\$ 159	\$ 29	\$ 115	\$ 37	\$ 95
High							
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	125	9
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 84	\$ 73	\$ 101	\$ 37	\$ 118	\$ 85	\$ 42
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 18: West Region, No DBB

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable- Large c&i	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing
Variable Costs (\$/MWh)	\$ 2	\$ 2	\$ 4	\$ 6	\$ 6	\$ 4	\$ 4
Demand Reduction Period (Hours)	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Start Year							
Base							
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	42	3
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 76	\$ 58	\$ 89	\$ 29	\$ 119	\$ 49	\$ 63
Low							
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	18	0
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 58	\$ 61	\$ 185	\$ 30	\$ 116	\$ 38	\$ 144
High							
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	51	5
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 84	\$ 70	\$ 104	\$ 37	\$ 121	\$ 86	\$ 56
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	69
July	-	46	46	96	186	69	18
August	-	33	33	96	186	18	-
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 19: System, No DBB

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable- Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	144	7
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 76	\$ 59	\$ 84	\$ 28	\$ 118	\$ 49	\$ 49
Low							
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	61	1
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 58	\$ 53	\$ 167	\$ 29	\$ 115	\$ 37	\$ 91
High							
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	177	14
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 84	\$ 72	\$ 102	\$ 37	\$ 119	\$ 85	\$ 45
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 20: East Region, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable- Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Start Year	2	2	4	6	6	4	4	10
Base								
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	51	5	19
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 75	\$ 58	\$ 82	\$ 27	\$ 117	\$ 50	\$ 40	\$ 14
Low								
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	22	1	6
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 57	\$ 52	\$ 159	\$ 28	\$ 115	\$ 38	\$ 89	\$ 13
High								
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	63	9	46
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 83	\$ 71	\$ 101	\$ 36	\$ 118	\$ 86	\$ 36	\$ 18
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 21: West Region, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable- Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Start Year	2009	2009	2009	2009	2009	2009	2009	2009
Base								
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	21	3	8
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 75	\$ 57	\$ 89	\$ 28	\$ 119	\$ 50	\$ 56	\$ 14
Low								
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	9	0	3
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 57	\$ 60	\$ 185	\$ 29	\$ 116	\$ 39	\$ 136	\$ 14
High								
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	26	5	19
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 83	\$ 69	\$ 104	\$ 37	\$ 121	\$ 86	\$ 48	\$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 22: System, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	72	7	28
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 75	\$ 58	\$ 84	\$ 27	\$ 118	\$ 50	\$ 42	\$ 14
Low								
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	30	1	9
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 57	\$ 52	\$ 167	\$ 29	\$ 115	\$ 38	\$ 84	\$ 13
High								
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	88	14	65
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 83	\$ 71	\$ 102	\$ 36	\$ 119	\$ 86	\$ 38	\$ 18
Hours Available by Month								
January								
February	3							
March								
April					240			
May					186			
June		8	8	96	180			
July		46	46	96	186	69	69	129
August		33	33	96	186	18	18	46
September				48	180			
October					279			
November								
December	84							

APPENDIX C – DETAILED CEM MODELING RESULTS

This appendix presents detailed Capacity Expansion Module (CEM) results for the 16 alternative future scenarios, 16 sensitivity analysis scenarios, and an additional set of sensitivity scenarios requested by public stakeholders.

ALTERNATIVE FUTURE AND SENSITIVITY ANALYSIS SCENARIO RESULTS

Table C.1 – Alternative Future Scenarios

CAF #	Name	Coal Cost: CO ₂ Adder/Coal Commodity Price	Gas/Electric Price	Load Growth	Renewable Sales Percentage due to RPS	Renewable PTC Availability	DSM Potential
0	Business As Usual	None/Medium	Medium	Medium	Low	Yes	Medium
1	Low Cost Coal/High Cost Gas	None/Low	High	Medium	Medium	Yes	Medium
2	with Low Load Growth	None/Low	High	Low	Medium	Yes	Medium
3	with High Load Growth	None/Low	High	High	Medium	Yes	Medium
4	High Cost Coal/Low Cost Gas	High/High	Low	Medium	Medium	Yes	Medium
5	with Low Load Growth	High/High	Low	Low	Medium	Yes	Medium
6	with High Load Growth	High/High	Low	High	Medium	Yes	Medium
7	Favorable Wind Environment	High/Medium	High	Medium	High	Yes	Medium
8	Unfavorable Wind Environment	None/Medium	Low	Medium	Low	No	Medium
9	High DSM Potential	High/Medium	High	Medium	Medium	Yes	High
10	Low DSM Potential	None/Medium	Low	Medium	Medium	Yes	Low
11	Medium Load Growth	Medium/Medium	Medium	Medium	Medium	Yes	Medium
12	Low Load Growth	Medium/Medium	Medium	Low	Medium	Yes	Medium
13	High Load Growth	Medium/Medium	Medium	High	Medium	Yes	Medium
14	Low Cost Portfolio Bookend	None/Low	Low	Low	Medium	Yes	Medium
15	High Cost Portfolio Bookend	High/High	High	High	Medium	No	Medium

Table C.2 – Sensitivity Analysis Scenarios

SAS#	Name	Basis
1	Plan to 12% capacity reserve margin	CAF #11
2	Plan to 18% capacity reserve margin	CAF #11
3	CO ₂ adder implementation in 2016	CAF #11
4	Regional transmission project	CAF #11
5-10 5-15 5-20	CO ₂ adder impact on resource selection: test \$15, \$20, \$25 per ton adders (approximately \$10, \$15, and \$20 in 1990 dollars)	CAF #11
6	Low wind capital cost	CAF #11
7	High wind capital cost	CAF #11
8	Low coal price	CAF #11
9	High coal price	CAF #11
10	Low IGCC capital cost	CAF #11
11	High IGCC capital cost	CAF #11
12	Replace a baseload pulverized resource with carbon-capture-ready IGCC	CAF #11
13	Replace a baseload resource with IGCC/single gasifier	CAF #11
14	Replace a baseload resource with IGCC/sequestration	CAF #11
15	Plan to "average of super-peak" load	CAF #11
16	"Favorable Wind Environment" scenario assuming permanent expiration of the renewables PTC beginning in 2008	CAF07("Favorable Wind Environment")

In the following tables, fossil fuel resource additions are reported as nameplate megawatts accrued as of the year listed. Wind resources, unless noted otherwise, are reported as the estimated megawatt peak capacity contribution accrued as of the year listed.

Table C.3 – Aggregate Resource Additions

Scenario	PVRR (millions)	Resource Additions (MW)									
		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	\$ 19,619	82	748	722	1,236	1,523	2,677	2,980	3,238	3,306	3,585
CAF01	\$ 18,071	135	749	722	1,237	1,526	2,692	3,173	3,153	3,236	3,509
CAF02	\$ 11,022	45	423	210	576	696	1,704	1,667	2,162	2,362	1,950
CAF03	\$ 30,159	228	1,106	1,271	1,999	2,517	3,819	4,157	5,080	5,636	6,057
CAF04	\$ 30,504	85	749	723	1,236	1,524	2,682	2,854	3,149	3,227	3,533
CAF05	\$ 23,920	45	424	211	576	695	1,670	1,661	1,722	1,638	1,730
CAF06	\$ 40,002	224	1,107	1,271	1,996	2,515	3,840	4,247	4,711	5,152	5,644
CAF07	\$ 33,339	151	749	718	1,236	1,520	2,692	2,887	3,183	3,258	3,535
CAF08	\$ 18,858	-	747	721	1,235	1,521	2,679	2,803	3,112	3,203	3,512
CAF09	\$ 33,213	151	749	721	1,236	1,524	2,697	2,878	3,140	3,233	3,540
CAF10	\$ 19,002	85	749	723	1,237	1,525	2,682	2,805	3,112	3,203	3,508
CAF11	\$ 24,606	135	749	723	1,238	1,524	2,673	2,838	3,126	3,209	3,510
CAF12	\$ 17,689	45	423	211	576	696	1,669	1,660	1,762	1,669	1,772
CAF13	\$ 35,024	222	1,105	1,268	1,996	2,504	3,831	4,197	4,737	5,142	5,748
CAF14	\$ 13,689	45	422	208	574	694	1,653	1,639	1,776	1,687	1,788
CAF15	\$ 49,234	82	1,109	1,268	2,001	2,511	3,838	4,259	4,917	5,172	5,745
SAS01	\$ 24,400	85	471	436	954	1,231	2,356	2,690	2,940	3,008	3,172
SAS02	\$ 24,983	299	1,021	995	1,527	1,826	3,013	3,187	3,465	3,562	3,918
SAS03	\$ 22,673	82	748	722	1,236	1,519	2,693	2,979	3,237	3,303	3,584
SAS04	\$ 24,182	85	748	723	1,236	1,522	2,694	3,174	3,150	3,257	3,543
SAS05-10	\$ 28,551	151	749	722	1,237	1,523	2,673	2,845	3,115	3,211	3,509
SAS05-15	\$ 32,390	135	749	724	1,237	1,524	2,673	2,791	3,103	3,200	3,501
SAS05-20	\$ 36,073	182	748	720	1,236	1,514	2,651	2,812	3,081	3,175	3,488
SAS06	\$ 24,282	326	746	711	1,240	1,528	2,706	2,872	3,166	3,242	3,546
SAS07	\$ 24,836	68	748	723	1,236	1,523	2,697	2,865	3,242	3,318	3,595
SAS08	\$ 24,401	122	749	723	1,237	1,524	2,702	3,184	3,159	3,245	3,560
SAS09	\$ 24,980	135	749	723	1,238	1,524	2,703	2,991	3,245	3,315	3,525
SAS10	\$ 24,559	122	749	723	1,237	1,524	2,684	3,173	3,123	3,208	3,505
SAS11	\$ 24,660	68	748	721	1,235	1,523	2,697	2,865	3,242	3,318	3,595
SAS12	\$ 24,976	122	749	722	1,236	1,524	2,684	2,897	3,153	3,247	3,558
SAS13	\$ 24,980	150	748	722	1,233	1,520	2,698	2,905	3,181	3,270	3,573
SAS14	\$ 25,521	106	748	722	1,236	1,522	2,683	2,896	3,152	3,248	3,558
SAS15	\$ 24,412	118	516	476	1,000	1,282	2,417	2,584	2,851	2,934	3,228
SAS16	\$ 35,049	64	747	722	1,236	1,523	2,693	2,874	3,296	3,320	3,572

Table C.4 – Wind Resource Additions

(Nameplate MW)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	300	300	300	300	300	300	300	300	300	300
CAF01	600	800	800	800	800	1,000	1,000	1,000	1,000	1,000
CAF02	200	400	400	400	400	400	400	400	400	400
CAF03	1,000	1,300	1,300	1,300	1,300	1,400	1,400	1,400	1,400	1,400
CAF04	400	400	400	400	400	400	500	500	500	1,400
CAF05	200	300	300	300	300	300	300	600	600	1,400
CAF06	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,500	1,800	2,200
CAF07	800	1,000	1,100	1,100	1,100	1,200	2,200	2,200	2,800	3,100
CAF08	-	-	-	-	-	-	-	-	-	-
CAF09	800	1,000	1,000	1,000	1,000	1,600	1,600	2,300	3,100	3,100
CAF10	400	400	400	400	400	400	400	400	400	400
CAF11	600	700	700	700	700	700	700	700	700	700
CAF12	200	300	300	300	300	400	400	400	400	400
CAF13	900	900	900	900	900	900	900	900	900	900
CAF14	200	300	400	400	400	400	400	400	400	400
CAF15	300	300	300	300	300	400	400	400	800	2,300
SAS01	400	500	500	500	500	600	600	600	600	600
SAS02	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,500	1,500
SAS03	300	400	400	400	400	400	400	400	400	400
SAS04	400	500	500	500	500	500	500	500	500	900
SAS05-10	800	900	900	900	900	900	1,100	1,100	1,200	1,200
SAS05-15	600	600	600	600	600	600	600	600	600	600
SAS05-20	1,100	1,200	1,200	1,200	1,200	1,900	1,900	1,900	1,900	2,800
SAS06	1,800	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
SAS07	300	300	300	300	300	300	400	400	400	500
SAS08	500	500	500	500	500	500	500	500	500	500
SAS09	600	700	700	700	700	700	700	700	700	700
SAS10	500	500	500	500	500	500	500	500	500	500
SAS11	300	400	400	400	400	400	400	400	400	400
SAS12	500	600	600	600	600	600	600	600	600	600
SAS13	600	700	700	700	700	700	700	700	700	700
SAS14	400	500	500	500	500	500	500	500	500	900
SAS15	600	700	700	700	700	800	900	900	900	900
SAS16	200	200	400	600	800	1,000	1,200	1,500	1,700	1,900

Table C.5 – Front Office Transactions

Figures shown are megawatts acquired in each year. Annual figures are not additive. Contract quantities were grossed up by the planning reserve margin to reflect the assumption that contract purchases are firm.

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	-	666	639	1,153	1,441	1,380	933	1,190	1,258	1,337
CAF01	-	599	573	1,088	1,377	1,380	1,111	591	674	197
CAF02	-	363	151	516	636	1,044	258	413	413	-
CAF03	-	848	988	1,697	2,133	1,380	219	444	492	116
CAF04	-	664	638	1,151	1,439	1,369	1,379	1,126	1,204	1,373
CAF05	-	355	143	507	627	1,378	1,369	1,380	1,296	1,291
CAF06	-	883	1,022	1,728	2,232	1,379	1,185	1,110	1,088	1,198
CAF07	-	583	515	1,033	1,317	1,363	1,380	726	758	973
CAF08	-	748	721	1,235	1,521	1,375	749	1,058	1,149	1,358
CAF09	-	583	555	1,071	1,358	1,380	811	805	765	1,072
CAF10	-	664	638	1,152	1,440	1,379	752	1,059	1,150	1,380
CAF11	-	601	575	1,090	1,377	1,379	1,380	919	1,002	1,303
CAF12	-	366	153	519	638	1,379	1,365	718	624	727
CAF13	-	883	1,045	1,755	1,961	1,355	1,366	1,156	811	909
CAF14	-	339	109	475	595	1,379	1,365	752	662	764
CAF15	-	1,027	1,160	1,874	2,083	1,380	1,051	459	649	987
SAS01	-	373	338	857	1,133	1,344	928	1,178	1,247	1,211
SAS02	-	722	696	1,228	893	1,408	1,415	1,352	1,416	1,022
SAS03	-	653	627	1,141	1,424	1,380	917	1,174	1,240	1,321
SAS04	-	651	626	1,139	1,425	1,379	1,109	1,084	1,191	1,380
SAS05-10	-	585	558	1,073	1,359	1,380	1,378	1,308	1,377	925
SAS05-15	-	614	589	1,102	1,389	1,302	1,379	941	1,038	1,339
SAS05-20	-	554	526	1,042	1,018	1,380	938	1,208	1,302	1,379
SAS06	-	406	370	899	1,188	1,370	1,380	923	999	1,304
SAS07	-	680	654	1,167	1,455	1,369	1,377	1,003	1,079	1,340
SAS08	-	627	600	1,114	1,402	1,380	1,112	1,087	1,173	1,148
SAS09	-	601	575	1,090	1,377	1,379	917	1,171	1,241	1,250
SAS10	-	627	600	1,114	1,402	1,380	1,119	1,068	1,153	1,251
SAS11	-	667	641	1,155	1,442	1,356	1,380	1,007	1,083	1,360
SAS12	-	614	588	1,102	1,381	1,380	843	1,099	1,194	1,304
SAS13	-	585	559	1,071	1,357	1,380	837	1,113	1,202	1,305
SAS14	-	630	604	1,118	1,404	1,380	843	1,099	1,195	1,380
SAS15	-	385	345	869	1,151	1,380	1,380	897	980	1,274
SAS16	-	683	613	1,080	1,334	1,372	782	413	413	649

Table C.6 – Gas Additions, Including Combined Heat & Power

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	-	-	-	-	-	125	125	125	125	125
CAF01	-	-	25	25	25	2,140	2,742	3,134	3,566	3,923
CAF02	-	-	-	-	-	100	100	100	100	100
CAF03	-	-	-	-	-	1,175	1,175	1,175	1,175	1,275
CAF04	-	-	-	-	-	-	-	-	-	-
CAF05	-	-	-	-	-	1,150	1,150	1,150	1,150	1,225
CAF06	-	-	-	-	-	734	759	759	759	759
CAF07	-	-	-	-	-	50	50	50	50	50
CAF08	-	-	-	-	302	1,628	1,628	1,628	1,628	1,628
CAF09	-	-	-	-	-	25	25	25	25	25
CAF10	-	-	25	25	327	1,211	1,211	1,211	1,211	1,211
CAF11	-	-	-	-	-	125	125	125	125	125
CAF12	-	-	-	-	634	634	734	734	734	734
CAF13	-	-	-	-	-	125	125	125	125	125
CAF14	-	-	-	-	-	125	125	125	125	125
CAF15	-	-	-	-	-	125	125	125	125	125
SAS01	-	-	25	25	25	2,140	2,742	3,134	3,566	3,923
SAS02	-	-	-	-	-	100	100	100	100	100
SAS03	-	-	-	-	-	1,175	1,175	1,175	1,175	1,275
SAS04	-	-	-	-	-	-	-	-	-	-
SAS05-10	-	-	-	-	-	979	1,029	1,029	1,029	1,029
SAS05-15	-	-	-	-	-	1,236	1,236	1,236	1,236	1,236
SAS05-20	-	-	-	-	302	759	1,361	1,361	1,361	1,361
SAS06	-	-	-	-	-	302	402	402	402	402
SAS07	-	-	-	-	-	634	684	684	684	684
SAS08	-	-	-	-	-	402	402	402	402	402
SAS09	-	-	-	-	-	427	427	427	427	427
SAS10	-	-	-	-	-	432	432	432	432	432
SAS11	-	-	-	-	-	634	659	659	659	659
SAS12	-	-	-	-	-	432	432	432	432	432
SAS13	-	-	-	-	-	402	402	402	402	402
SAS14	-	-	-	-	-	432	432	432	432	432
SAS15	-	-	-	-	-	407	457	457	457	457
SAS16	-	-	-	-	-	75	75	75	75	75

Table C.7 – IGCC Additions

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	-	-	-	-	-	-	-	-	-	200
CAF01	-	-	-	-	-	-	-	500	500	500
CAF02	-	-	-	-	-	-	-	-	200	200
CAF03	-	-	-	-	-	-	-	697	1,205	2,002
CAF04	-	-	-	-	-	-	-	-	-	-
CAF05	-	-	-	-	-	-	-	-	-	-
CAF06	-	-	-	-	-	-	-	-	-	-
CAF07	-	-	-	-	-	-	-	200	200	200
CAF08	-	-	-	-	-	-	-	-	-	-
CAF09	-	-	-	-	-	-	-	200	200	200
CAF10	-	-	-	-	-	-	-	-	-	-
CAF11	-	-	-	-	-	-	-	-	-	-
CAF12	-	-	-	-	-	-	-	-	-	-
CAF13	-	-	-	-	-	-	-	-	-	508
CAF14	-	-	-	-	-	-	-	-	-	-
CAF15	-	-	-	-	-	-	-	500	500	500
SAS01	-	-	-	-	-	-	-	-	-	200
SAS02	-	-	-	-	-	-	-	-	-	0
SAS03	-	-	-	-	-	-	-	-	-	200
SAS04	-	-	-	-	-	-	-	-	-	-
SAS05-10	-	-	-	-	-	-	-	-	-	-
SAS05-15	-	-	-	-	-	-	-	-	-	-
SAS05-20	-	-	-	-	-	-	-	-	-	-
SAS06	-	-	-	-	-	-	-	-	-	-
SAS07	-	-	-	-	-	-	-	-	-	-
SAS08	-	-	-	-	-	-	-	-	-	-
SAS09	-	-	-	-	-	-	-	-	-	200
SAS10	-	-	-	-	-	-	-	-	-	200
SAS11	-	-	-	-	-	-	-	-	-	0
SAS12	-	-	-	-	-	-	750	750	750	950
SAS13	-	-	-	-	-	-	750	750	750	950
SAS14	-	-	-	-	-	-	750	750	750	750
SAS15	-	-	-	-	-	-	-	-	-	-
SAS16	-	-	-	-	-	-	-	-	-	-

Table C.8 – Pulverized Coal Additions

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	-	-	-	-	-	940	1,690	1,690	1,690	1,690
CAF01	-	-	-	-	-	940	1,690	1,690	1,690	2,440
CAF02	-	-	-	-	-	600	1,350	1,690	1,690	1,690
CAF03	-	-	-	-	-	940	2,440	2,440	2,440	2,440
CAF04	-	-	-	-	-	-	-	-	-	-
CAF05	-	-	-	-	-	-	-	-	-	-
CAF06	-	-	-	-	-	-	-	-	-	-
CAF07	-	-	-	-	-	940	940	1,690	1,690	1,690
CAF08	-	-	-	-	-	-	750	750	750	750
CAF09	-	-	-	-	-	940	1,690	1,690	1,690	1,690
CAF10	-	-	-	-	-	-	750	750	750	750
CAF11	-	-	-	-	-	340	340	1,090	1,090	1,090
CAF12	-	-	-	-	-	-	-	750	750	750
CAF13	-	-	-	-	-	600	940	1,690	2,440	2,440
CAF14	-	-	-	-	-	-	-	750	750	750
CAF15	-	-	-	-	-	940	1,690	2,440	2,440	2,440
SAS01	-	-	-	-	-	600	1,350	1,350	1,350	1,350
SAS02	-	-	-	-	-	600	600	940	940	1,690
SAS03	-	-	-	-	-	940	1,690	1,690	1,690	1,690
SAS04	-	-	-	-	-	940	1,690	1,690	1,690	1,690
SAS05-10	-	-	-	-	-	-	-	340	340	1,090
SAS05-15	-	-	-	-	-	-	-	750	750	750
SAS05-20	-	-	-	-	-	-	-	-	-	-
SAS06	-	-	-	-	-	600	600	1,350	1,350	1,350
SAS07	-	-	-	-	-	600	600	1,350	1,350	1,350
SAS08	-	-	-	-	-	600	1,350	1,350	1,350	1,690
SAS09	-	-	-	-	-	600	1,350	1,350	1,350	1,350
SAS10	-	-	-	-	-	600	1,350	1,350	1,350	1,350
SAS11	-	-	-	-	-	600	600	1,350	1,350	1,350
SAS12	-	-	-	-	-	600	600	600	600	600
SAS13	-	-	-	-	-	600	600	600	600	600
SAS14	-	-	-	-	-	600	600	600	600	600
SAS15	-	-	-	-	-	340	340	1,090	1,090	1,090
SAS16	-	-	-	-	-	940	1,690	2,440	2,440	2,440

Table C.9 – Demand Side Management Additions

(MW Capacity)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	-	-	-	-	-	150	150	150	150	150
CAF01	-	-	-	-	-	151	151	151	151	151
CAF02	-	-	-	-	-	-	-	-	-	-
CAF03	-	-	-	19	101	163	163	163	163	163
CAF04	-	-	-	-	-	78	78	78	78	78
CAF05	-	-	-	-	-	99	99	99	99	99
CAF06	-	-	-	19	34	97	97	169	169	169
CAF07	-	-	-	-	-	58	58	58	58	58
CAF08	-	-	-	-	-	129	129	129	129	129
CAF09	-	-	-	-	-	64	64	64	64	64
CAF10	-	-	-	-	-	68	68	68	68	68
CAF11	-	-	-	-	-	73	211	211	211	211
CAF12	-	-	-	-	-	145	150	150	150	150
CAF13	-	-	-	19	19	26	41	41	41	41
CAF14	-	-	-	-	-	150	150	150	150	150
CAF15	-	-	-	19	19	198	198	198	198	198
SAS01	-	-	-	-	-	161	161	161	161	161
SAS02	-	-	-	-	-	73	140	140	161	161
SAS03	-	-	-	-	-	153	153	153	153	153
SAS04	-	-	-	-	-	153	153	153	153	153
SAS05-10	-	-	-	-	-	150	209	209	209	209
SAS05-15	-	-	-	-	-	-	41	41	41	41
SAS05-20	-	-	-	-	-	154	154	154	154	244
SAS06	-	-	-	-	-	94	150	150	150	150
SAS07	-	-	-	-	-	26	124	124	124	124
SAS08	-	-	-	-	-	198	198	198	198	198
SAS09	-	-	-	-	-	150	150	150	150	150
SAS10	-	-	-	-	-	150	150	150	150	150
SAS11	-	-	-	-	-	26	145	145	145	145
SAS12	-	-	-	-	-	137	137	137	137	137
SAS13	-	-	-	-	-	153	153	153	153	153
SAS14	-	-	-	-	-	153	153	153	153	201
SAS15	-	-	-	-	-	131	211	211	211	211
SAS16	-	-	-	-	-	73	73	73	73	73

ADDITIONAL CEM SENSITIVITY ANALYSIS SCENARIO RESULTS

This section reports the detailed CEM results for an additional set of sensitivity scenarios requested by participants at the August 2006 public input meeting. Specifically, participants requested that sensitivities to scenario variables be tested against different sets of “base” scenario assumptions. All but one of the scenarios in Table 7.1 were intended to examine the CEM’s response to varying assumptions around the “medium” (CAF11) case. Participants requested studies that varied the assumptions around the business-as-usual (CAF00), the low cost bookend (CAF14), and the high cost bookend (CAF16) scenarios.

Table C.10 summarizes the additional sensitivity scenarios. Note that sensitivities were only selected if they involve a key scenario variable or planning assumption (such as the planning reserve margin level), or are compatible with respect to how the alternative future scenario was defined. For example, the sensitivities for testing alternative CO₂ adder values are not compatible with the business-as-usual case, since that case assumes no adder to begin with. Regarding the regional transmission project scenario, additional forward price forecasts would be required to support alternative market conditions, which PacifiCorp deemed as too burdensome given the other research priorities. A few other sensitivities were excluded because they are intended to fulfill specific analytical requirements from the Oregon Public Utility Commission, such as SAS15 (“plan to average of super-peak load”).

Table C.10 – Additional Sensitivity Scenarios for CEM Optimization

SAS#	Name	Alternative Future Scenario Used		
		Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)
1	Plan to 12% capacity reserve margin	X	X	X
2	Plan to 18% capacity reserve margin	X	X	X
3	CO ₂ adder implementation in 2016			
4	Regional transmission project			
5a	CO ₂ adder impact on resource selection: \$10/ton (1990\$)		X	X
5b	CO ₂ adder impact on resource selection: \$15/ton (1990\$)		X	X
5c	CO ₂ adder impact on resource selection: \$20/ton (1990\$)		X	
6	Low wind capital cost	X	X	X
7	High wind capital cost	X	X	X

Tables C.11 through C.15 compare PVRR and resource addition results for each of the additional sensitivity scenarios. The first table reports PVRR. The remaining five tables report nameplate capacity accrued by 2016 for total resources, wind, gas, pulverized coal, and IGCC, respectively.

Table C.11 – Present Value of Revenue Requirements Comparison (\$ Billion)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	\$19,488	\$13,382	\$48,825	\$24,400
Plan to 18% capacity reserve margin	\$19,933	\$13,672	\$49,936	\$24,983
CO ₂ adder implementation in 2016	--	--	--	\$22,673
Regional transmission project	--	--	--	\$24,182
CO ₂ adder impact on resource selection: \$10/ton (1990\$)	--	\$19,803	\$39,693	\$28,551
CO ₂ adder impact on resource selection: \$15/ton (1990\$)	--	\$22,303	\$44,773	\$32,390
CO ₂ adder impact on resource selection: \$20/ton (1990\$)	--	\$24,589	\$49,234	\$36,073
Low wind capital cost	\$19,424	\$13,523	\$47,018	\$24,282
High wind capital cost	\$19,867	\$13,703	\$48,123	\$24,836

Table C.12 – Total Resources Accrued by 2016 (Megawatts)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	3,327	1,507	5,338	3,172
Plan to 18% capacity reserve margin	3,831	2,028	6,068	3,918
CO ₂ adder implementation in 2016	--	--	--	3,584
Regional transmission project	--	--	--	3,543
CO ₂ adder impact on resource selection: \$10/ton (1990\$)	--	1,775	6,010	3,509
CO ₂ adder impact on resource selection: \$15/ton (1990\$)	--	1,735	5,724	3,501
CO ₂ adder impact on resource selection: \$20/ton (1990\$)	--	1,722	5,745	3,488
Low wind capital cost	3,535	1,790	5,708	3,546
High wind capital cost	3,584	1,789	5,687	3,595

Table C.13 – Wind Resources Accrued by 2016 (Nameplate Megawatts)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	200	400	2,100	600
Plan to 18% capacity reserve margin	1,300	400	2,400	1,500
CO ₂ adder implementation in 2016	--	--	--	400
Regional transmission project	--	--	--	900
CO ₂ adder impact on resource selection: \$10/ton (1990\$)	--	400	600	1,200
CO ₂ adder impact on resource selection: \$15/ton (1990\$)	--	400	800	600
CO ₂ adder impact on resource selection: \$20/ton (1990\$)	--	600	2,300	2,800
Low wind capital cost	1,300	500	3,200	2,000
High wind capital cost	200	400	3,100	500

Table C.14 – Gas Resources Accrued by 2016 (Megawatts)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	25	25	849	125
Plan to 18% capacity reserve margin	125	548	1,631	734
CO ₂ adder implementation in 2016	--	--	--	125
Regional transmission project	--	--	--	125
CO ₂ adder impact on resource selection: \$10/ton (1990\$)	--	302	1,361	1,029
CO ₂ adder impact on resource selection: \$15/ton (1990\$)	--	125	1,336	1,236
CO ₂ adder impact on resource selection: \$20/ton (1990\$)	--	125	1,211	1,361
Low wind capital cost	50	75	1,029	402
High wind capital cost	602	75	849	684

Table C.15 – Pulverized Coal Resources Accrued by 2016 (Megawatts)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	1,690	--	2,440	1,350
Plan to 18% capacity reserve margin	1,690	--	2,440	1,690
CO ₂ adder implementation in 2016	--	--	--	1,690
Regional transmission project	--	--	--	1,690
CO ₂ adder impact on resource selection: \$10/ton (1990\$)	--	--	2,440	1,090
CO ₂ adder impact on resource selection: \$15/ton (1990\$)	--	--	2,440	750
CO ₂ adder impact on resource selection: \$20/ton (1990\$)	--	--	2,440	--
Low wind capital cost	1,690	750	2,440	1,350
High wind capital cost	1,690	750	2,440	1,350

Table C.16 – IGCC Resources Accrued by 2016 (Megawatts)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	200	--	500	200
Plan to 18% capacity reserve margin	200	--	500	--
CO ₂ adder implementation in 2016	--	--	--	200
Regional transmission project	--	--	--	--
CO ₂ adder impact on resource selection: \$10/ton (1990\$)	--	--	1,494	--
CO ₂ adder impact on resource selection: \$15/ton (1990\$)	--	--	997	--
CO ₂ adder impact on resource selection: \$20/ton (1990\$)	--	--	500	--
Low wind capital cost	200	--	500	--
High wind capital cost	--	--	500	--

For the detailed CEM results tables, fossil fuel resource additions are reported as nameplate megawatts accrued as of the year listed. Wind resources are reported as the estimated megawatt peak capacity contribution accrued as of the year listed. The annual figures are not additive. Contract quantities were also grossed up by the planning reserve margin to reflect the assumption that contract purchases are firm.

Table C.17 – CEM Results: Aggregate Resource Additions

Scenario	PVRR (millions)	Resource Additions (MW)										PVRR (Million\$/2016 MW)
		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	
BAU/ 12% PRM	\$ 19,488	45	486	449	978	1,263	2,431	2,880	2,972	3,046	3,327	5.9
BAU/ 18% PRM	\$ 19,933	271	1,002	975	1,496	1,789	2,881	3,185	3,456	3,543	3,831	5.2
BAU/Low Wind Cap Cost	\$ 19,424	236	749	715	1,237	1,528	2,693	3,174	3,443	3,243	3,535	5.5
BAU/High Wind Cap Cost	\$ 19,867	45	748	722	1,236	1,523	2,683	2,855	3,231	3,302	3,584	5.5
Low Cost Bookend/ 12% PRM	\$ 13,382	68	142	68	296	416	1,413	1,404	1,489	1,406	1,507	8.9
Low Cost Bookend/ 18% PRM	\$ 13,672	106	681	475	831	943	1,950	1,938	2,025	1,927	2,028	6.7
Low Cost Bookend/ \$10 CO ₂	\$ 19,803	68	424	211	576	688	1,680	1,672	1,759	1,674	1,775	11.2
Low Cost Bookend/ \$15 CO ₂	\$ 22,303	85	423	209	575	673	1,653	1,641	1,724	1,640	1,735	12.9
Low Cost Bookend/ \$20 CO ₂	\$ 24,589	98	422	209	572	659	1,652	1,638	1,722	1,638	1,722	14.3
Low Cost Bookend/ Low Wind Cap Cost	\$ 13,523	122	420	207	572	691	1,670	1,662	1,722	1,634	1,790	7.6
Low Cost Bookend/ High Wind Cap Cost	\$ 13,703	45	425	209	575	694	1,669	1,660	1,711	1,632	1,789	7.7
High Cost Bookend/ 12% PRM	\$ 48,825	-	839	1,008	1,724	2,233	3,528	3,911	4,399	4,738	5,338	9.1
High Cost Bookend/ 18% PRM	\$ 49,936	82	1,404	1,565	2,308	2,837	4,158	4,506	5,283	5,521	6,068	8.2
High Cost Bookend/ \$10 CO ₂	\$ 39,693	82	1,109	1,268	2,001	2,511	3,828	4,237	4,907	5,137	6,010	6.6
High Cost Bookend/ \$15 CO ₂	\$ 44,773	72	1,108	1,267	1,999	2,510	3,808	4,204	4,653	5,143	5,724	7.8
High Cost Bookend/ \$20 CO ₂	\$ 49,234	82	1,109	1,268	2,001	2,511	3,838	4,259	4,917	5,172	5,745	8.6

Scenario	PVRR (millions)	Resource Additions (MW)										PVRR (Million\$/2016 MW)
		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	
Low Cost Bookend/ Low Wind Cap Cost	\$ 47,018	368	1,130	1,298	2,031	2,528	3,863	4,211	4,661	5,152	5,708	8.2
Low Cost Bookend/ High Wind Cap Cost	\$ 48,123	226	1,106	1,270	1,995	2,511	3,778	4,158	4,645	5,090	5,687	8.5

Note: Business as Usual (BAU)

Table C.18 – CEM Results: Wind Resource Additions

(Nameplate MW)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/ 12% PRM	200	200	200	200	200	200	200	200	200	200
BAU/ 18% PRM	1,200	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
BAU/ Low Wind Cap Cost	1,100	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
BAU/ High Wind Cap Cost	200	200	200	200	200	200	200	200	200	200
Low Cost Bookend/ 12% PRM	300	300	300	300	300	300	300	400	400	400
Low Cost Bookend/ 18% PRM	400	400	400	400	400	400	400	400	400	400
Low Cost Bookend/ \$10 CO ₂	300	300	300	300	300	300	400	400	400	400
Low Cost Bookend/ \$15 CO ₂	400	400	400	400	400	400	400	400	400	400
Low Cost Bookend/ \$20 CO ₂	500	500	500	500	500	500	500	600	600	600
Low Cost Bookend/ Low Wind Cap Cost	500	500	500	500	500	500	500	500	500	500
Low Cost Bookend/ High Wind Cap Cost	200	200	300	300	300	300	300	400	400	400
High Cost Bookend/ 12% PRM	-	200	300	300	300	600	600	600	1,400	2,100
High Cost Bookend/ 18% PRM	300	300	300	300	300	400	400	400	600	2,400
High Cost Bookend/ \$10 CO ₂	300	300	300	300	300	400	400	400	600	600
High Cost Bookend/ \$15 CO ₂	300	300	300	300	300	400	400	400	600	800
High Cost Bookend/ \$20 CO ₂	300	300	300	300	300	400	400	400	800	2,300
Low Cost Bookend/ Low Wind Cap Cost	2,200	2,800	2,800	2,800	2,800	2,800	2,800	3,100	3,100	3,200
Low Cost Bookend/ High Wind Cap Cost	1,000	1,000	1,000	1,000	1,000	2,000	2,100	3,000	3,100	3,100

Table C.19 – CEM Results: Front Office Transactions

Figures shown are megawatts acquired in each year, Contract quantities were grossed up by the planning reserve margin to reflect the assumption that contract purchases are firm. Annual figures are not additive.

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/12% PRM	-	440	404	933	1,218	1,380	1,079	1,171	1,244	1,326
BAU/18% PRM	-	719	692	1,213	1,505	1,380	934	1,205	1,291	1,380
BAU/ Low Wind Cap Cost	-	499	465	987	1,278	1,380	1,111	1,380	1,180	1,272
BAU/ High Wind Cap Cost	-	703	676	1,190	1,478	1,096	1,267	894	965	1,247
Low Cost Bookend/ 12% PRM	-	74	-	228	347	1,337	1,328	1,377	1,294	1,370
Low Cost Bookend/ 18% PRM	-	575	369	726	837	1,296	1,285	1,372	1,273	1,374
Low Cost Bookend/ \$10 CO ₂	-	355	143	507	620	1,310	1,274	1,362	1,277	1,378
Low Cost Bookend/ \$15 CO ₂	-	338	124	490	588	1,373	1,360	1,369	1,285	1,380
Low Cost Bookend/ \$20 CO ₂	-	324	112	474	561	1,380	1,366	1,380	1,296	1,380
Low Cost Bookend/ Low Wind Cap Cost	-	298	85	450	569	1,378	1,370	1,380	1,291	698
Low Cost Bookend/ High Wind Cap Cost	-	380	127	492	612	1,362	1,352	1,380	1,302	708
High Cost Bookend/ 12% PRM	-	791	914	1,631	1,728	1,380	1,013	1,002	1,244	995
High Cost Bookend/ 18% PRM	-	1,303	1,136	1,879	2,294	1,363	210	488	690	971
High Cost Bookend/ \$10 CO ₂	-	1,027	1,160	1,874	2,083	1,380	1,038	459	674	553
High Cost Bookend/ \$15 CO ₂	-	1,036	1,195	1,908	2,111	1,377	1,022	972	697	749
High Cost Bookend/ \$20 CO ₂	-	1,027	1,160	1,874	2,083	1,380	1,051	459	649	987
Low Cost Bookend/ Low Wind Cap Cost	-	679	846	1,561	1,153	1,370	968	856	597	1,107
Low Cost Bookend/ High Wind Cap Cost	-	880	1,019	1,725	2,175	1,380	1,009	914	1,342	1,189

Table C.20 – CEM Results: Gas Additions, Including Combined Heat and Power

(Nameplate MW)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/ 12% PRM	-	-	-	-	-	25	25	25	25	25
BAU/ 18% PRM	-	-	-	-	-	125	125	125	125	125
BAU/ Low Wind Cap Cost	-	-	-	-	-	50	50	50	50	50
BAU/ High Wind Cap Cost	-	-	-	-	-	602	602	602	602	602
Low Cost Bookend/ 12% PRM	-	-	-	-	-	-	-	-	-	25
Low Cost Bookend/ 18% PRM	-	-	-	-	-	548	548	548	548	548
Low Cost Bookend/ \$10 CO ₂	-	-	-	-	-	302	302	302	302	302
Low Cost Bookend/ \$15 CO ₂	-	-	-	-	-	50	50	125	125	125
Low Cost Bookend/ \$20 CO ₂	-	-	-	-	-	75	75	125	125	125
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	25	25	75	75	75
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	75	75	75	75	75
High Cost Book- end/ 12% PRM	-	-	25	25	417	849	849	849	849	849
High Cost Book- end/ 18% PRM	-	-	327	327	327	1,631	1,631	1,631	1,631	1,631
High Cost Book- end/ \$10 CO ₂	-	-	25	25	327	1,361	1,361	1,361	1,361	1,361
High Cost Book- end/ \$15 CO ₂	-	-	-	-	302	1,336	1,336	1,336	1,336	1,336
High Cost Book- end/ \$20 CO ₂	-	-	25	25	327	1,211	1,211	1,211	1,211	1,211
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	904	1,004	1,004	1,004	1,004	1,029
Low Cost Bookend/ High Wind Cap Cost	-	-	25	25	25	849	849	849	849	849

Table C.21 – CEM Results: IGCC Additions

(Nameplate MW)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/ 12% PRM	-	-	-	-	-	-	-	-	-	200
BAU/ 18% PRM	-	-	-	-	-	-	-	-	-	200
BAU/Low Wind Cap Cost	-	-	-	-	-	-	-	-	-	200
BAU/High Wind Cap Cost	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ 12% PRM	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ 18% PRM	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$10 CO ₂	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$15 CO ₂	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$20 CO ₂	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	-	-	-	-	-
High Cost Book-end/ 12% PRM	-	-	-	-	-	-	-	500	500	500
High Cost Book-end/ 18% PRM	-	-	-	-	-	-	-	500	500	500
High Cost Book-end/ \$10 CO ₂	-	-	-	-	-	-	-	500	500	1,494
High Cost Book-end/ \$15 CO ₂	-	-	-	-	-	-	-	500	500	997
High Cost Book-end/ \$20 CO ₂	-	-	-	-	-	-	-	500	500	500
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	-	-	500	500	500
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	-	-	500	500	500

Table C.22 – CEM Results: Pulverized Coal Additions

(Nameplate MW)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/ 12% PRM	-	-	-	-	-	940	1,690	1,690	1,690	1,690
BAU/ 18% PRM	-	-	-	-	-	940	1,690	1,690	1,690	1,690
BAU/ Low Wind Cap Cost	-	-	-	-	-	940	1,690	1,690	1,690	1,690
BAU/ High Wind Cap Cost	-	-	-	-	-	940	940	1,690	1,690	1,690
Low Cost Bookend/ 12% PRM	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ 18% PRM	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$10 CO ₂	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$15 CO ₂	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$20 CO ₂	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	-	-	-	-	750
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	-	-	-	-	750
High Cost Book- end/ 12% PRM	-	-	-	-	-	940	1,690	1,690	1,690	2,440
High Cost Book- end/ 18% PRM	-	-	-	-	-	940	2,440	2,440	2,440	2,440
High Cost Book- end/ \$10 CO ₂	-	-	-	-	-	940	1,690	2,440	2,440	2,440
High Cost Book- end/ \$15 CO ₂	-	-	-	-	-	940	1,690	1,690	2,440	2,440
High Cost Book- end/ \$20 CO ₂	-	-	-	-	-	940	1,690	2,440	2,440	2,440
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	940	1,690	1,690	2,440	2,440
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	940	1,690	1,690	1,690	2,440

Table C.23 – CEM Results: Demand-side Management Additions

(MW Capacity)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/ 12% PRM	-	-	-	-	-	41	41	41	41	41
BAU/ 18% PRM	-	-	-	-	-	153	153	153	153	153
BAU/ Low Wind Cap Cost	-	-	-	-	-	73	73	73	73	73
BAU/ High Wind Cap Cost	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ 12% PRM	-	-	-	-	-	7	7	7	7	7
Low Cost Bookend/ 18% PRM	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$10 CO ₂	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$15 CO ₂	-	-	-	-	-	145	145	145	145	145
Low Cost Bookend/ \$20 CO ₂	-	-	-	-	-	99	99	99	99	99
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	145	145	145	145	145
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	150	150	150	150	150
High Cost Bookend/ 12% PRM	-	-	-	-	19	198	198	198	198	198
High Cost Bookend/ 18% PRM	-	19	19	19	133	140	140	140	140	140
High Cost Bookend/ \$10 CO ₂	-	-	-	19	19	46	46	46	46	46
High Cost Bookend/ \$15 CO ₂	-	-	-	19	24	46	46	46	46	46
High Cost Bookend/ \$20 CO ₂	-	-	-	19	19	198	198	198	198	198
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	19	19	97	97	97	97	97
Low Cost Bookend/ High Wind Cap Cost	-	-	-	19	85	195	195	195	195	195

APPENDIX D – SUPPLEMENTARY PORTFOLIO INFORMATION

This appendix reports additional information for the risk analysis portfolios discussed in Chapter 7. This information consists of carbon dioxide emissions quantity and cost data, as well as a component cost breakdown of the stochastic mean Present Value of Revenue Requirements (PVRR) reported for the risk analysis portfolios.

CARBON DIOXIDE EMISSIONS

Table D.1 shows cumulative CO₂ emissions for 2007 through 2026 attributable to retail sales only, allocated to each state.

Table D.2 reports unit emission costs (cents/MWh) by new fossil fuel resource for the risk analysis portfolios considered as finalists for preferred portfolio selection (Group 2 portfolios). The results are reported for 2016 based on the \$8/ton CO₂ adder case.

Table D.1 – CO₂ Emissions Attributable to Retail Sales by State

Group 1 Portfolios

ID	CO ₂ Emissions attributable to Retail Sales, 2007-2026 (1000 Tons)						
	System Total	California	Oregon	Washington	Utah	Idaho	Wyoming
RA1	1,120,694	17,481	262,468	85,363	500,054	65,432	189,897
RA2	1,111,948	17,342	260,377	84,678	496,227	64,910	188,413
RA3	1,115,336	17,388	261,003	84,889	498,000	65,073	188,984
RA4	1,121,824	17,494	262,636	85,420	500,715	65,475	190,084
RA5	1,115,003	17,388	261,047	84,899	497,671	65,077	188,920
RA6	1,104,309	17,228	258,687	84,122	492,675	64,484	187,112
RA7	1,089,439	16,997	255,229	82,988	486,009	63,619	184,596
RA8	1,128,175	17,594	264,156	85,917	503,490	65,854	191,163
RA9	1,123,075	17,517	263,001	85,538	501,159	65,564	190,296
RA10	1,119,534	17,462	262,184	85,270	499,558	65,360	189,699
RA11	1,109,867	17,308	259,850	84,508	495,373	64,779	188,049
RA12	1,110,384	17,320	260,043	84,566	495,486	64,824	188,146

Group 2 Portfolios

ID	CO ₂ Emissions attributable to Retail Sales, 2007-2026 (1000 Tons)						
	\$8 Adder	California	Oregon	Washington	Utah	Idaho	Wyoming
RA13	1,127,571	17,586	264,045	85,886	503,165	65,828	191,061
RA14	1,064,710	16,624	249,713	81,179	474,567	62,234	180,393
RA15	1,068,540	16,683	250,584	81,465	476,315	62,453	181,041
RA16	1,057,885	16,517	248,100	80,652	471,557	61,832	179,227
RA17	1,075,848	16,796	252,296	82,027	479,570	62,881	182,278

Table D.2 – Unit Emission Costs for Group 2 Risk Analysis Portfolio Resources, 2016

Portfolio, Location, and Fossil Fuel Resources	Generation (GWh)	SO ₂	NO _x	Hg	CO ₂
		Cost	Cost	Cost	Cost
Cents/MWh					
Portfolio RA13					
East					
Utah supercritical pulverized coal	1,642	15.8	38.1	5.8	880.5
Wyoming supercritical pulverized coal	4,011	16.1	39.1	5.9	898.8
Utah supercritical pulverized coal 2 (added in 2017)	-				
Wyoming supercritical pulverized coal 2 (added in 2018)	-				
Combined Heat and Power	140	0.1	13.2	1.4	286.4
West					
Combined Heat and Power	395	0.1	13.1	1.4	287.0
Portfolio RA14					
East					
Utah supercritical pulverized coal	1,584	15.8	38.1	5.8	880.5
Wyoming supercritical pulverized coal	3,864	16.1	39.1	5.9	898.8
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,283	0.1	4.8	2.0	411.5
Combined Cycle Combustion Turbine, G Class, 1x1 w/ duct firing	1,571	0.1	4.8	2.0	405.7
Combined Heat and Power	143	0.1	13.2	1.4	286.4
West					
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,086	0.1	4.8	2.0	416.6
Combined Heat and Power	402	0.1	13.1	1.4	287.0
Portfolio RA15					
East					
Utah supercritical pulverized coal	1,607	15.8	38.1	5.8	880.5
Wyoming supercritical pulverized coal	3,926	16.1	39.1	5.9	898.8
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,382	0.1	4.8	2.0	411.5
Combined Heat & Power	142	0.1	13.2	1.4	286.4
West					
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	1,956	0.1	4.8	2.0	416.6
Combined Heat and Power	392	0.1	13.1	1.4	287.0
Portfolio RA16					
East					
Utah supercritical pulverized coal	1,544	15.8	38.1	5.8	880.5
Wyoming supercritical pulverized coal	3,821	16.1	39.1	5.9	898.8
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,320	0.1	4.8	2.0	411.5
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,320	0.1	4.8	2.0	411.5
Combined Heat and Power	143	0.1	13.2	1.4	286.4
West					
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,058	0.1	4.8	2.0	416.6
Combined Heat and Power	401	0.1	13.1	1.4	287.0
Portfolio RA17					
East					
Utah supercritical pulverized coal	1,651	15.8	38.1	5.8	880.5
Wyoming supercritical pulverized coal	4,044	16.1	39.1	5.9	898.8
Combined Heat & Power	141	0.1	13.2	1.4	286.4
West					
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	1,836	0.1	4.8	2.0	416.6
Combined Heat and Power	382	0.1	13.1	1.4	287.0

Figures D.1 and D.2 show the CO₂ intensity (as measured by CO₂ tons produced per megawatt-hours generated) for the Group 2 portfolios in the \$8/ton and \$61/ton CO₂ adder cases from 2007 through 2016.

Figure D.1 – Annual CO₂ Intensity, 2007-2016 (\$8 CO₂ Adder Case)
 (From generation plus amount assigned to net wholesale market purchases)



Figure D.2 – Annual CO₂ Intensity, 2007-2016 (\$61 CO₂ Adder Case)
(From generation plus amount assigned to net wholesale market purchases)



PORTFOLIO PVRR COST COMPONENT COMPARISON

Tables D.3 through D.5 shows the breakdown of each portfolio's stochastic mean PVRR by variable and fixed cost components. These costs reflect the \$8/ton CO₂ cost adder scenario. Table D.3 reports Group 1 risk analysis portfolios assuming a cap-and-trade compliance strategy as described in the Environmental Externality Cost section of Chapter 6. Tables D.4 and D.5 report the cost component breakdown for Group 2 risk analysis portfolios for both the CO₂ cap-and-trade and tax compliance strategies.

Table D.3 – Group 1: Portfolio PVRR Cost Components (Cap-and-Trade Strategy)

Cost Component (\$000)	RA1	RA2	RA3	RA4	RA5	RA6
Variable Cost						
Total Fuel Cost	10,965,989	11,219,657	10,747,203	11,071,618	10,863,819	11,466,519
Variable O&M Cost	1,666,016	1,688,456	1,653,825	1,685,170	1,664,323	1,609,748
Total Emission Cost	(491,456)	(524,670)	(583,581)	(494,617)	(541,909)	(633,384)
Long Term Contracts and Front Office Transactions	4,063,902	2,989,769	3,993,441	2,784,539	2,990,020	3,942,403
Spot Market Balancing						
Sales	(7,171,405)	(6,701,180)	(7,028,212)	(6,484,120)	(6,654,682)	(6,790,395)
Purchases	4,097,605	4,256,922	4,156,083	4,506,043	4,064,023	4,526,764
Energy Not Served	629,175	506,358	578,218	599,325	407,713	649,402
Total Variable Net Power Costs	13,759,825	13,435,313	13,516,978	13,667,958	12,793,306	14,771,056
Real Levelized Fixed Costs						
Real Levelized Fixed Costs	7,585,994	8,078,725	7,998,119	7,821,194	9,444,528	7,541,457
Total PVRR						
Total PVRR	21,345,820	21,514,038	21,515,097	21,489,152	22,237,834	22,312,513

Cost Component (\$000)	RA7	RA8	RA9	RA10	RA11	RA12
Variable Cost						
Total Fuel Cost	11,011,967	10,861,455	10,650,718	10,807,128	10,476,806	10,584,210
Variable O&M Cost	1,662,836	1,661,127	1,600,405	1,621,957	1,626,325	1,625,553
Total Emission Cost	(615,865)	(493,480)	(528,346)	(517,475)	(576,401)	(583,010)
Long Term Contracts and Front Office Transactions	2,986,551	3,765,884	3,855,182	4,014,157	3,914,856	3,572,191
Spot Market Balancing						
Sales	(6,755,434)	(6,813,214)	(6,840,773)	(7,064,978)	(7,013,125)	(6,751,045)
Purchases	4,138,731	4,552,750	4,467,441	4,140,306	4,167,820	4,456,951
Energy Not Served	496,355	738,005	823,267	698,510	583,165	695,599
Total Variable Net Power Costs	12,925,142	14,272,526	14,027,895	13,699,605	13,179,447	13,600,449
Real Levelized Fixed Costs						
Real Levelized Fixed Costs	8,717,103	7,199,096	7,935,847	8,182,478	8,589,968	8,153,395
Total PVRR						
Total PVRR	21,642,245	21,471,622	21,963,742	21,882,083	21,769,415	21,753,844

Table D.4 – Group 2: Portfolio PVRR Cost Components (CO₂ Cap-and-Trade Compliance Strategy)

Cost Component (\$000)	RA13	RA14	RA15	RA16	RA17
Variable Cost					
Total Fuel Cost	11,879,724	12,740,475	12,687,088	12,893,187	12,496,322
Variable O&M Cost	1,677,644	1,688,639	1,686,253	1,695,132	1,675,585
Total Emission Cost	(500,740)	(686,096)	(675,164)	(707,522)	(660,752)
Long Term Contracts and Front Office Transactions	4,463,924	3,381,073	3,498,015	3,400,556	3,959,801
Spot Market Balancing					
Sales	(7,970,503)	(8,139,526)	(8,129,546)	(8,311,108)	(8,156,926)
Purchases	5,011,221	4,781,176	4,805,009	4,626,554	4,858,925
Energy Not Served	942,290	546,119	614,736	504,489	670,814
Total Variable Net Power Costs	15,503,559	14,311,859	14,486,390	14,101,289	14,843,769
Real Levelized Fixed Costs	6,506,394	7,247,005	7,145,760	7,523,537	6,906,261
Total PVRR	22,009,953	21,558,864	21,632,150	21,624,826	21,750,030

Table D.5 – Group 2: Portfolio PVRR Cost Components (CO₂ Tax Compliance Strategy)

Cost Component (\$000)	RA13	RA14	RA15	RA16	RA17
Variable Cost					
Total Fuel Cost	11,879,724	12,740,475	12,687,088	12,893,187	12,496,322
Variable O&M Cost	1,677,644	1,688,639	1,686,253	1,695,132	1,675,585
Total Emission Cost	4,419,596	4,232,883	4,243,852	4,211,342	4,258,307
Long Term Contracts and Front Office Transactions	4,463,924	3,381,073	3,498,015	3,400,556	3,959,801
Spot Market Balancing					
Sales	(7,970,503)	(8,139,526)	(8,129,546)	(8,311,108)	(8,156,926)
Purchases	5,011,221	4,781,176	4,805,009	4,626,554	4,858,925
Energy Not Served	942,290	546,119	614,736	504,489	670,814
Total Variable Net Power Costs	20,423,895	19,230,838	19,405,407	19,020,153	19,762,827
Real Levelized Fixed Costs					
	6,506,394	7,247,005	7,145,760	7,523,537	6,906,261
Total PVRR	26,930,289	26,477,843	26,551,166	26,543,691	26,669,089

APPENDIX E – STOCHASTIC RISK ANALYSIS METHODOLOGY

OVERVIEW

PacifiCorp analyzes potential portfolios over possible future conditions to assess the performance of each portfolio under uncertainty. Global Energy’s Planning and Risk (PaR) model is used to perform a stochastic assessment of portfolios in which system loads, hydroelectric energy availability, thermal unit outages, and wholesale electric and gas prices are varied to reflect uncertainty. Stochastic representations of these variables include specific volatility and correlations parameters. In the case of four of the five uncertainties described previously (PaR treats thermal outages separately), there are potentially short-term and long-term stochastic parameters (volatilities and correlations). The following is a discussion of the stochastic model specification, the short-term and long-term parameters and results of the stochastic simulation studies.

STOCHASTIC VARIABLES

PacifiCorp’s 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) and
- Hydroelectric generation

The PaR’s stochastic tool determines a set of stochastic model parameters based on data entered by the user. 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. 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 Stochastic Model

PaR’s stochastic model is a two factor (a short-run and a long-run factor) short-run mean reverting model. Variable processes assume normality or log-normality as appropriate. 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. 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.

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. 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 parameters are derived from a random-walk with drift regression. The standard error of the random-walk regression defines the long-run volatility for the regional electricity load variables. In the case of the natural gas and electricity market prices, the standard error of the random walk regression is interpolated with the volatilities from the company’s Official Forward Price curve for March 31, 2006 over the twenty year 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.

For a detailed specification of the PaR stochastic model, please refer to the 2004 IRP Appendix G.

STOCHASTIC OUTPUT

Presented below are graphical stylized outputs from the 100 stochastic iterations made by the Planning and Risk model. Eastern and western natural gas and electricity market prices (Figures E.1 through E.8) are presented showing the frequency of prices for 2007 and 2016. In the case of stochastic regional electricity loads (Figures E.9 through E.13), the 90th, 75th, 25th and 10th percentiles as well as the mean are presented. For hydroelectric generation (Figures E.14 and E.15), the 75th, 50th, 25th percentiles are presented.

Figure E.1 – 2007 Frequency of Eastern (Palo Verde) Electricity Market Prices – 100 Iterations

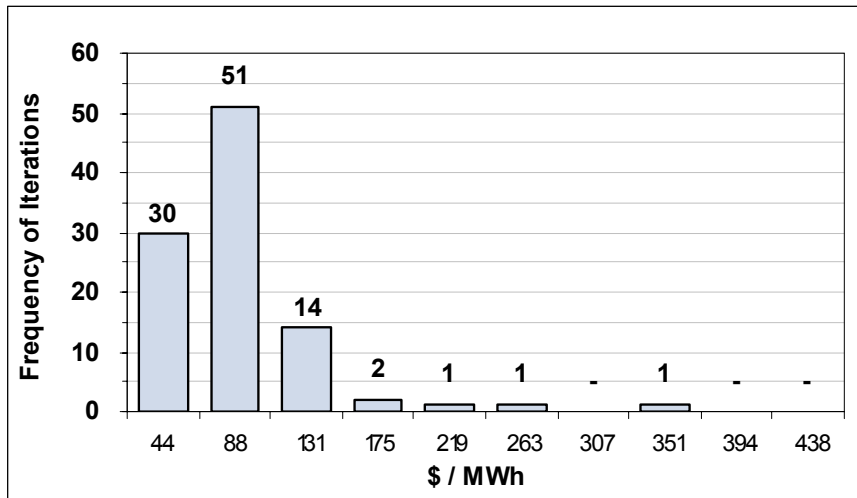


Figure E.2 – 2016 Frequency of Eastern (Palo Verde) Electricity Market Prices – 100 Iterations

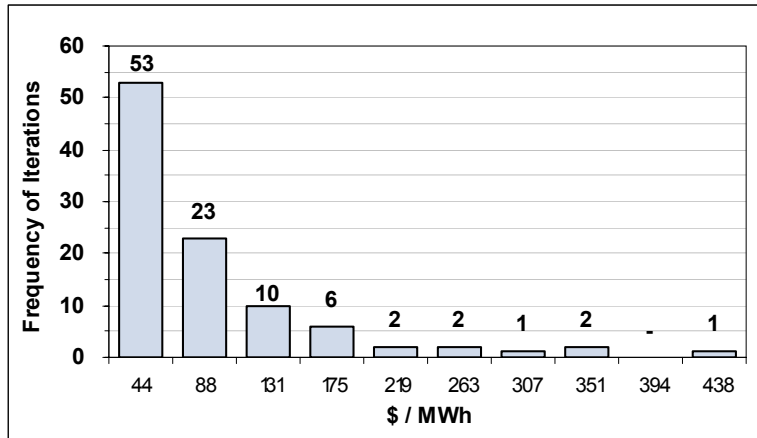


Figure E.3 – 2007 Frequency of Western (Mid C) Electricity Market Prices – 100 Iterations

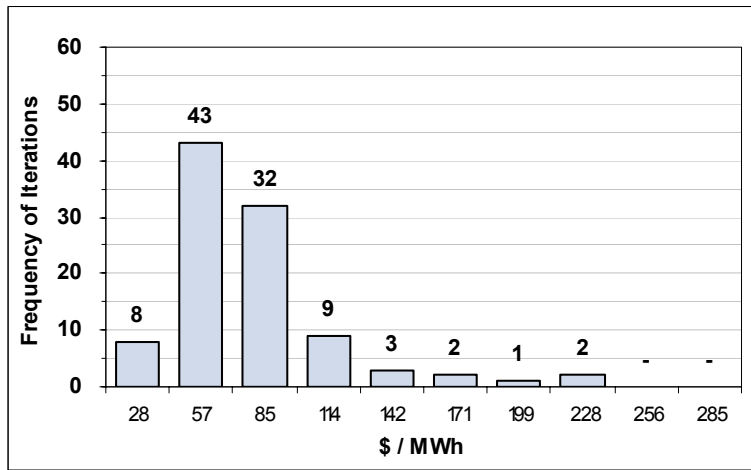


Figure E.4 – 2016 Frequency of Western (Mid C) Electricity Market Prices – 100 Iterations

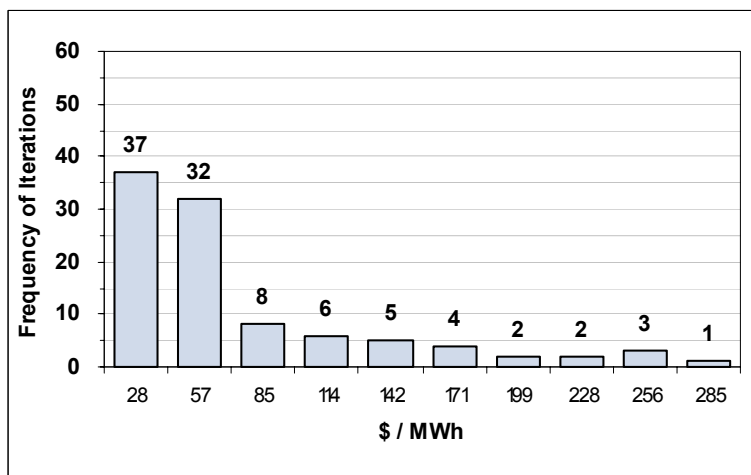


Figure E.5 – 2007 Frequency of Eastern Natural Gas Market Prices – 100 Iterations

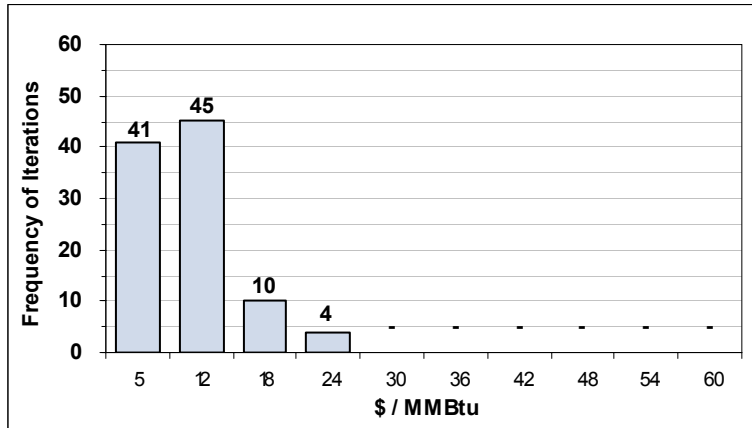


Figure E.6 – 2016 Frequency of Eastern Natural Gas Market Prices – 100 Iterations

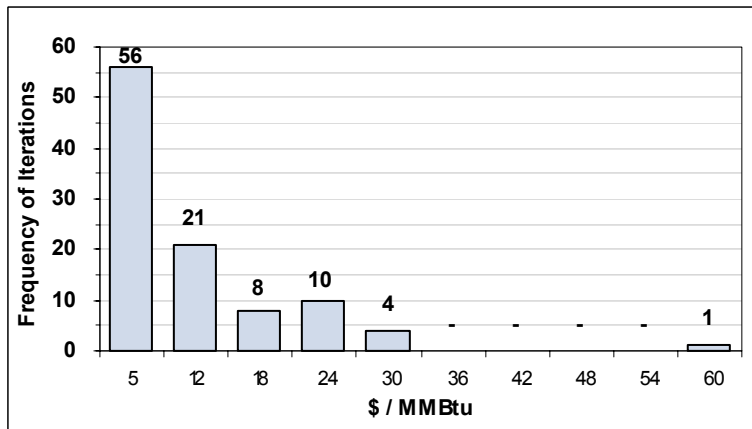


Figure E.7 – 2007 Frequency of Western Natural Gas Market Prices – 100 Iterations

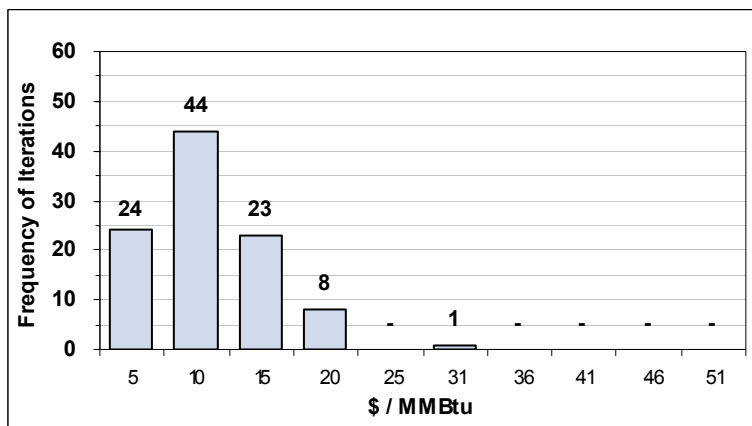


Figure E.8 – 2016 Frequency of Western Natural Gas Market Prices – 100 Iterations

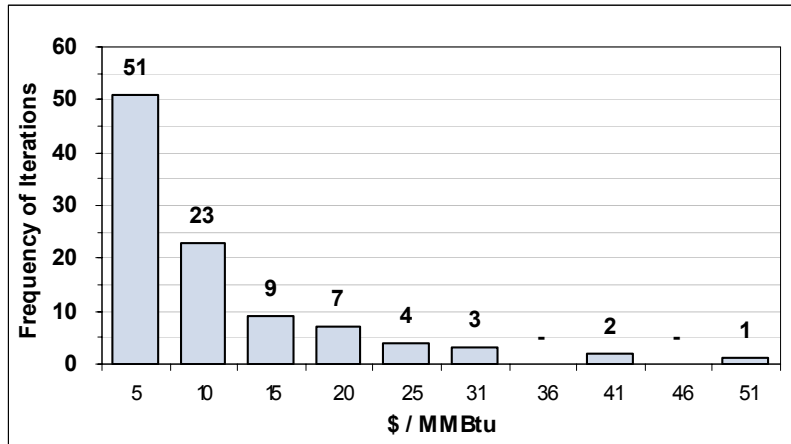


Figure E.9 – Goshen Loads

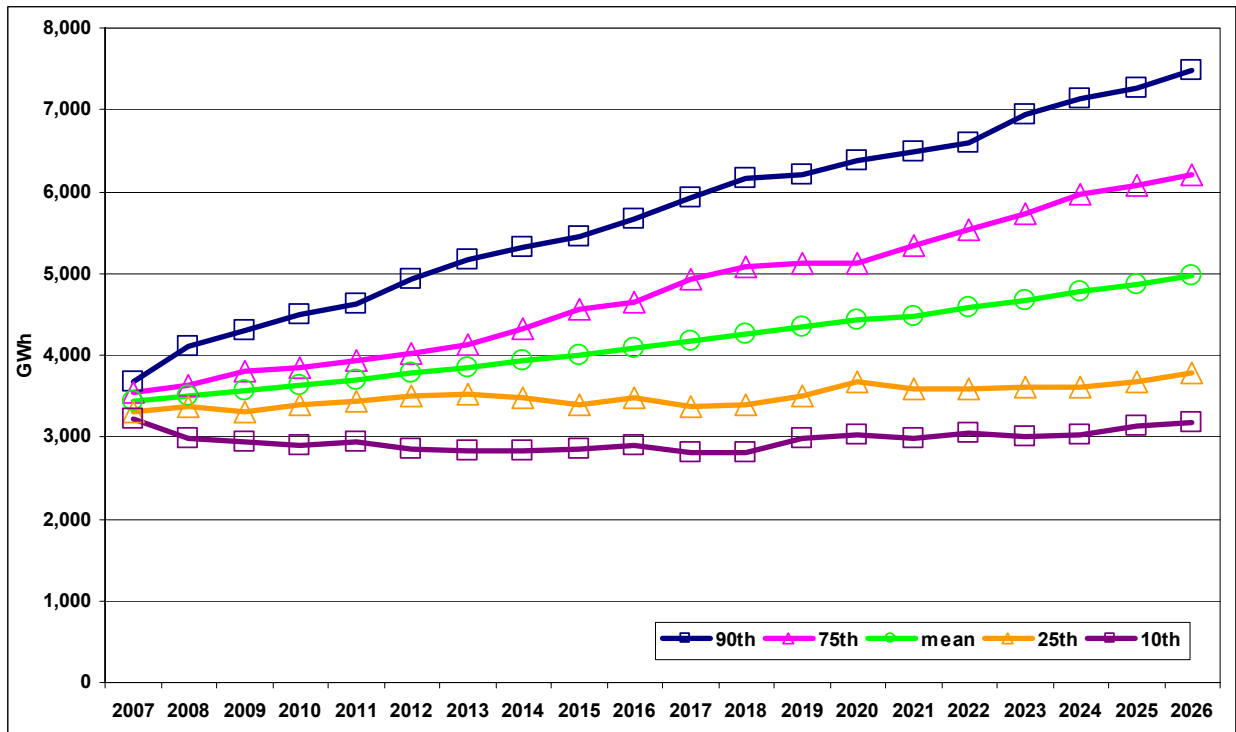


Figure E.10 – Utah Loads

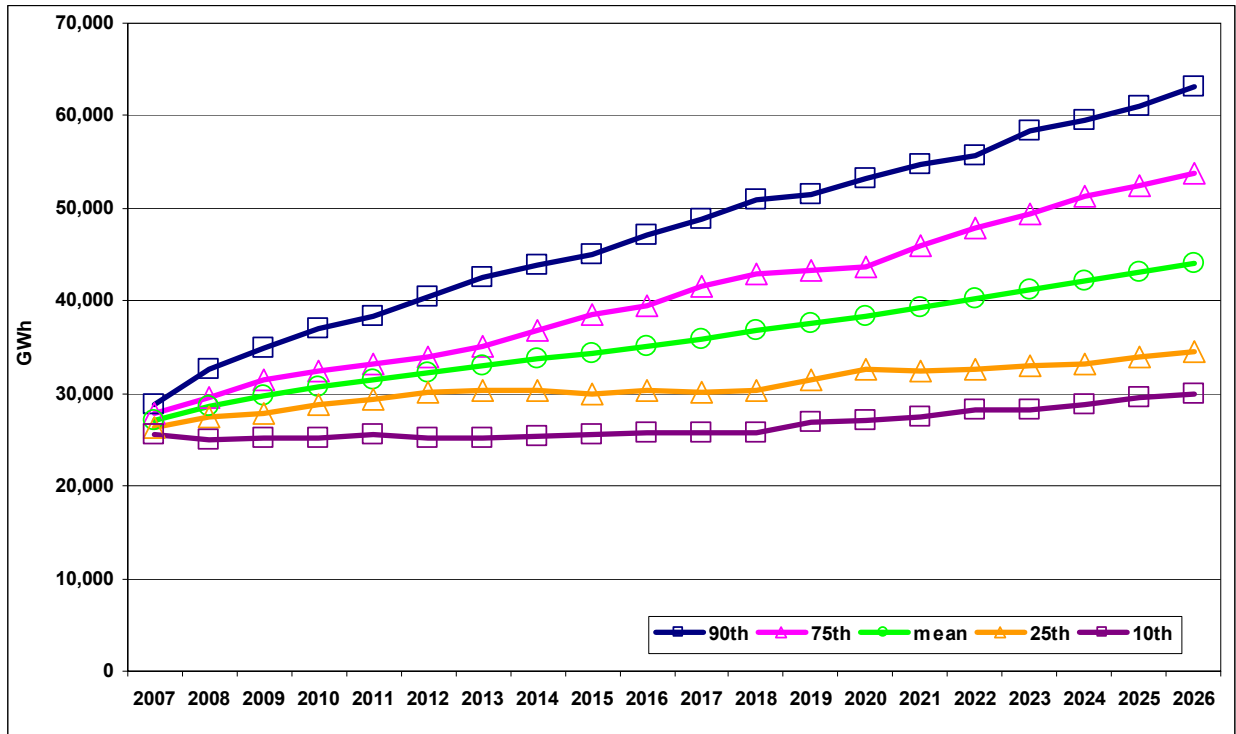


Figure E.11 – Washington Loads

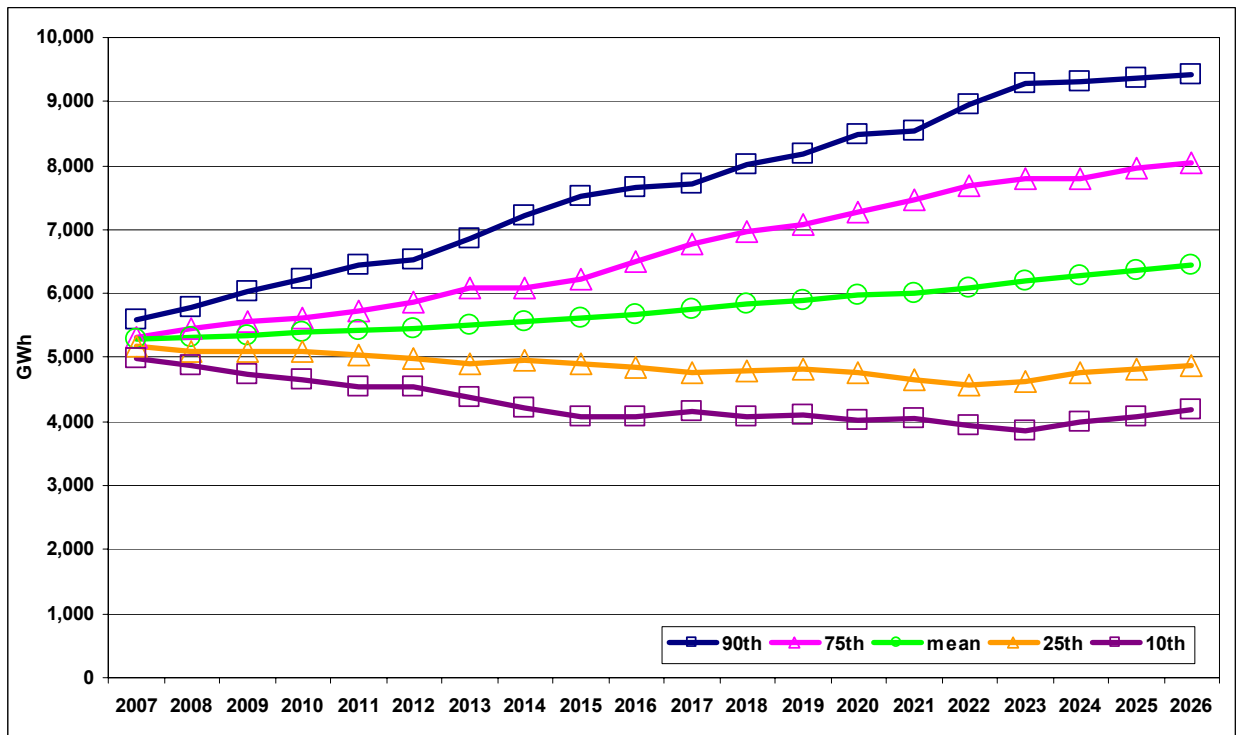


Figure E.12 – West Main (California and Oregon) Loads

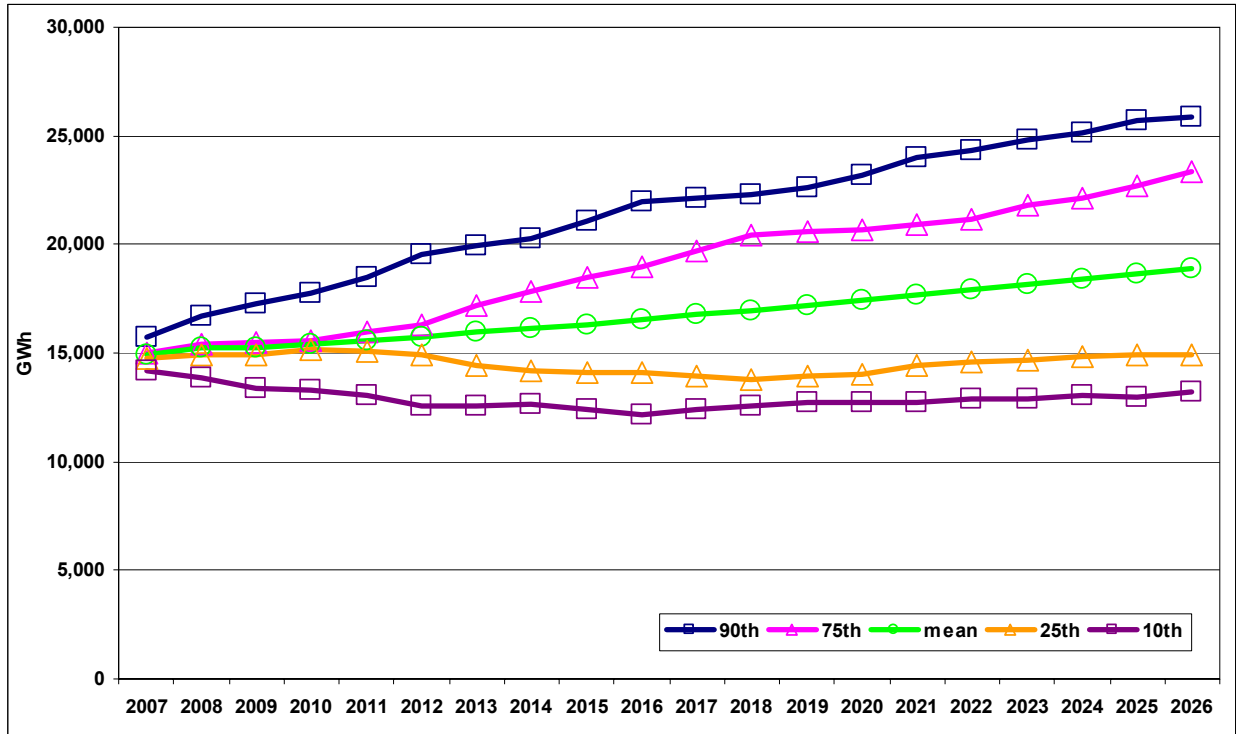


Figure E.13 – Wyoming Loads

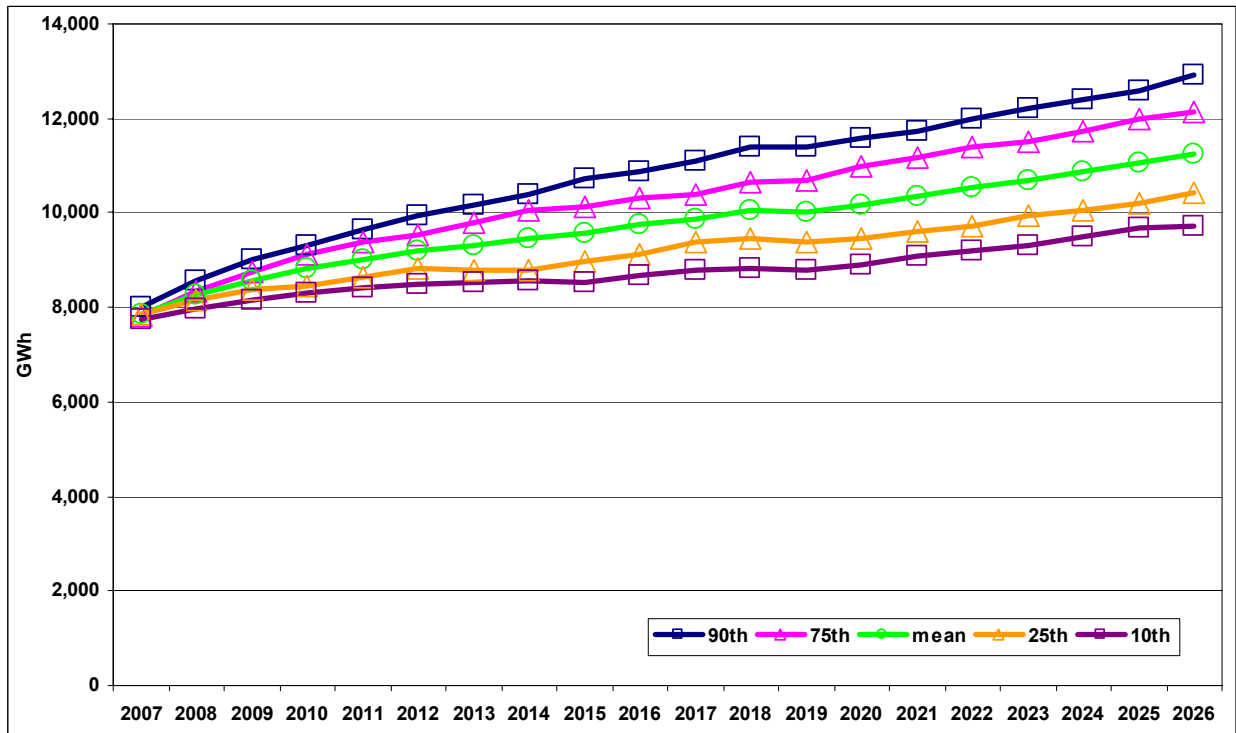


Figure E.14 – 2007 Hydroelectric Generation Percentile

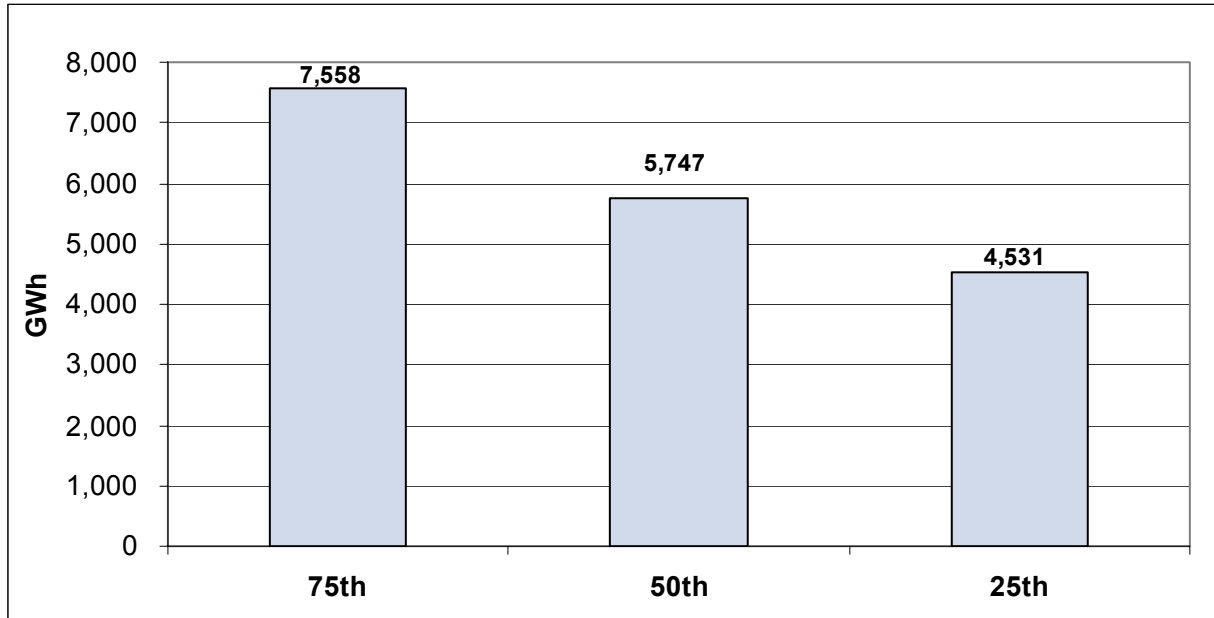
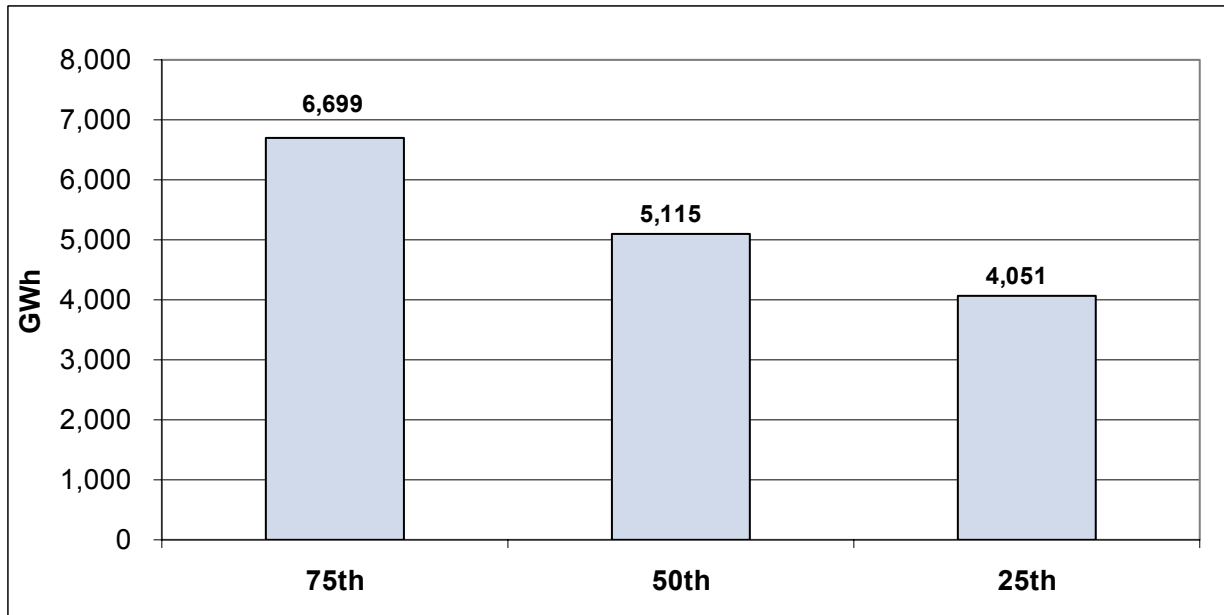


Figure E.15 – 2016 Hydroelectric Generation Percentile



APPENDIX F – PUBLIC INPUT PROCESS

A critical element of this resource plan is the public input process. PacifiCorp has pursued an open and collaborative approach involving the Commissions, customers and other stakeholders in PacifiCorp’s planning process prior to making resource planning decisions. Since these decisions can have significant economic and environmental consequences, conducting the resource plan with transparency and full participation from Commissions and other interested and affected parties is essential.

The public has been involved in this resource plan from its earliest stages and at each decisive step. Participants have both shared comments and ideas and received information. As reflected in the report, many of the comments provided by the participants have been adopted by PacifiCorp and have contributed to the quality of this resource plan. PacifiCorp will adopt further comments going forward, either as elements of the Action Plan or as future refinements to the planning methodology.

The cornerstone of the public input process has been full-day public input meetings held approximately every six weeks throughout the year-long plan development period. These meetings have been held jointly in three locations, Salt Lake City, Portland and Cheyenne (Starting from the April 20, 2006), using telephone and video conferencing technology, to encourage wide participation while minimizing travel burdens and respecting everyone’s busy schedules.

The 2007 public input meetings were augmented by a series of focused technical workshops to provide an opportunity to discuss complex topics for a multi-state utility in more detail.

PARTICIPANT LIST

Among the organizations that were represented and actively involved in this collaborative effort were:

Commissions

- Idaho Public Utilities Commission
- Oregon Public Utilities Commission
- Public Service Commission of Utah
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission

Intervenors

- Citizen’s Utility Board of Oregon
- Committee for Consumer Services State of Utah
- Energy Trust of Oregon
- Energy Strategies, LLC
- Industrial Customers of Northwest Utilities
- Mountain West Consulting, LLC

- Northwest Energy Efficiency Alliance
- Northwest Power and Conservation Council
- NW Energy Coalition
- Oregon Department of Energy
- Renewables Northwest Project
- Salt Lake City
- Salt Lake Community Action Program
- Southwest Energy Efficiency Project
- Sierra Club , Utah Chapter
- Utah Association of Energy Users
- Utah Clean Energy Alliance
- Utah Division of Air Quality
- Utah Division of Public Utilities
- Utah Energy Office
- Utah Geological Survey
- Utah Governor Office
- Utah Legislative Watch
- Wasatch Clean Air Coalition
- Western Resource Advocates
- West Wind Wires
- Wyoming Industrial Energy Consumers
- Wyoming Office Of Consumer Advocacy

Others

- Portland General Electric (PGE)
- Puget Sound Energy (PSE)
- Avista Utilities
- Quantec LLC
- John Klingele
- Global Energy Decisions, LLC

PacifiCorp extends its gratitude for the time and energy these participants have given to the resource plan. Your participation has contributed significantly to the quality of this plan, and your continued participation will help as PacifiCorp strives to improve its planning efforts going forward.

PUBLIC INPUT MEETINGS

PacifiCorp hosted eight full-day public input meetings, three technical workshops and three general meetings between the 2004 and 2007 IRP process which discussed various issues including inputs and assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public input meetings and the technical workshops.

2005 Public Process

May 18, 2005 – General Meeting

- Results of IRP Stakeholder Satisfaction Survey
- Overview of PacifiCorp Transmission
- Procurement Update
 - Implementation of Supply Side Actions in 2004 IRP Action Plan
 - Renewables RFP
 - RFP 2009
 - Front Office Transactions
- DSM Update
 - DSM in the 2004 IRP
 - Class 1 and Class 2 Update
 - DSM Procurement
- Update on Inputs and Assumptions
- Update on Models
 - PaR Conversion
 - Capacity Expansion Module

August 3, 2005 – General Meeting

- Load Forecasting Annual Review
 - National Economic Outlook
 - Regional Economic Review
 - Tools and Inputs of the Residential Forecast
 - Preliminary Residential Sales Forecast
- IRP Benchmarking Study
 - Scope and Overview
 - Findings
- IRP Action Plan Update
 - RFP 2003 B Renewable
 - RFP 2009
 - RFP 2011
 - Transmission (Regional Initiatives)
 - DSM Update
 - CEM Model Update
- 2004 IRP Update Plan
 - Outline
 - Schedule

October 5, 2005 – General Meeting

- Update on IRP Acknowledgement
- Load and Resource Balance Update
- New Portfolio Development / Overview of Analysis
- Status of Update Filing
- Progress on IRP Action Plan
 - RFP 2003 B Renewable, RFP 2009

- DSM Update
- Load Forecasting Technical Workshop - Annual Review
 - Comparisons of State Economic Forecasts
 - Commercial Electric Model Design and Inputs
 - Preliminary Commercial Economic and Sales Forecast

2006 Public Process

December 7, 2005 – General Meeting

- Overview of 2006 IRP Public Process
 - IRP Team Update
 - 2006 IRP Work Plan
 - PIM Participant Working Group (“WG”) Approach
 - Public Process Expectations
- 2006 IRP Studies
- 2004 IRP Update Summary and Revised Action Plan

January 13, 2006 – Renewables Workshop

- Review and discuss Wind Resource Analysis Plan
- Discuss Capacity Expansion Module (CEM) renewable supply curve modeling approach
- Summary
- Comments, Questions, and Suggestions
- Z-Statistic Method for Estimating Resource Peak Load Carrying Capability

January 24, 2006 – Load Forecasting Workshop

- Preliminary Industrial Energy Sales Forecast
 - State by State
 - Mix and Growth by Sector – 2007 and 2017
 - Sector by Sector Model Review
- Hourly Load Forecast
 - General Model Specification by Jurisdiction
 - Forecast Process
 - Improvements in the Process
 - System Coincident Peak Demand & Jurisdiction Contribution Results
 - State Peak Demands
 - Next Steps
- Price Elasticity
 - Price Elasticity in Current Models
 - Econometric Elasticity Calculations
 - Price Reaction of Customers Who Called About the Rate Change
 - Elasticity Among Customer Sub-Groups
 - Potential Further Research

February 10, 2006 – Demand-Side Management Workshop

- 2004 IRP DSM modeling Review
- Modeling Plan for 2006 IRP
 - Planning Drivers and Objectives
 - Modeling Approach Overview
 - Program Assumptions for 2006 IRP
- 2005 DSM RFP Summary and Challenges
- Summation and Next Steps

April 20, 2006 – General Meeting

Update on IRP Inputs, Assumptions, and Studies

- Climate Change Policy Developments
- CO2 Analysis in the 2006 IRP
- Integrated Gasification Combined Cycle (IGCC) Analysis Update
- Treatment of IGCC in the 2006 IRP
- Long-Term Load Forecast
- Preliminary Load & Resource Balance

May 10, 2006 – General Meeting

- Natural Gas and Electricity Forecasts
- Renewables Studies
- Procurement Update

June 7, 2006 – General Meeting

- Demand-Side Management: Class I & III Resource Assessment Update
- Procurement Update: Demand-Side Management
- Procurement Update: Supply-Side Resources
- IRP Resource Alternatives
- IRP Transmission Analysis Approach
- Portfolio Analysis Scenarios and Risk Analysis
- Resource Adequacy/Capacity Planning Margin

August 23, 2006 – General Meeting

- Introduction: Capacity Expansion Module (CEM) Analysis
- Scenario Review
- General Observations
 - Total Portfolio Costs
 - Generation, Demand-Side Management (DSM), and Market Purchases
 - Transmission
 - Sensitivity Studies
- CO2 Adder Impacts
- Summary Results
- Modeling Conclusions and Candidate Portfolio Development Process

Appendix:

- Modeling Results - Annual Resource Additions by Scenario

October 31, 2006 – General Meeting

- Candidate Portfolio Development
- Detailed Simulation Results and Conclusions
 - Stochastic Cost/Risk Trade-off Analysis Results
 - Reliability Analysis Results
 - CO2 emissions for \$8/ton CO2 adder case
- Quantec DSM Proxy Supply Curve Study
- Feedback on Capacity Expansion Module Results
- IRP Document Overview

2007 Public Process**February 1, 2007 – General Meeting**

- Status of the Integrated Resource Plan
- Status of the 2012 Request for Proposal
- Conclusions resulting from stakeholder feedback
- Proposed path forward
- Impact on the current Integrated Resource Plan
- Discussion and Comments

April 18, 2007 – General Meeting

- Load Forecast Update
 - Summary of Changes to Forecast
 - Changes in Economic Conditions
 - Major Sales Changes by Jurisdiction
- Load and Resource Balance Update
- Preferred Portfolio
- Action Plan
- Portfolio Modeling Update
 - Risk Analysis Portfolio Development
 - Cost and Risk Performance Results
 - Customer Rate Impacts
 - Carbon Dioxide Emissions Footprint
 - Supply Reliability Measures
- Class 2 DSM Decrement Analysis

PARKING LOT ISSUES

During the course of the public input meetings, certain concerns or questions needed additional explanation from PacifiCorp. These questions or issues were taken off-line or put in a “parking lot.” PacifiCorp either responded in writing in detail to address these parking lot issues, or in many cases, addressed them in a subsequent public input meeting or workshop. PacifiCorp responded to different complex questions that covered all aspects of the IRP.

Additionally, for the 2007 planning cycle, PacifiCorp provided meeting summaries for each of the public meetings reflecting a synopsis of what was discussed during the meeting. These summaries can be found on the internet website (<http://www.pacificorp.com/Article/Article23848.html>) and provide additional details on a particular IRP public meeting.

PUBLIC REVIEW OF IRP DRAFT DOCUMENT

This section summarizes the substantive comments on the draft IRP document submitted by IRP public participants and provides PacifiCorp's responses. The comments and responses are grouped by topic.

At the public meeting held on October 31, 2006, the company requested that parties focus on compliance with state IRP standards and guidelines when submitting comments on the draft IRP. PacifiCorp distributed the IRP draft document for public comment on April 20, 2007, with a comment due date of May 11, 2007. The company received comments from seven parties in time to be considered for the final IRP report:

- Utah Public Service Commission Staff (UPSC)
- The Utah Committee of Consumer Services (UCCS)
- The Utah Division of Public Utilities (UDPU)
- Utah Association of Energy Users (UAE)
- Western Resource Advocates (WRA)
- The NW Energy Coalition (NVEC)
- Renewable Northwest Project (RNP)

To characterize the comments at a high level, parties sought justification for, or cited perceived deficiencies in, (1) the scope of resources evaluated and their characterization (DSM, renewables, and IGCC in particular), (2) the treatment and interpretation of modeled risk factors and reliability, and (3) the decision criteria used to select preferred portfolio resources. A number of parties also submitted detailed questions and requests for supporting data.

To address the written comments, PacifiCorp modified the final IRP report to include more justification of its analytical conclusions and resource decisions, and answered specific technical questions to the extent possible given the IRP filing schedule. PacifiCorp also supplemented the "IRP Regulatory Compliance" appendix with two tables that outline how the company interpreted and complied with each of the IRP standards for Oregon and Utah (Tables I.3 and I.4 in Appendix I). The company considered the written comments when completing these tables. Responses to questions and data requests that could not be included in the final IRP report or addressed in this section will be handled as separate follow-up responses.

Portfolio Optimality

A number of parties disagree with, or at least question, whether the preferred portfolio development process meets Utah IRP standards and Guidelines with respect to "selection of the optimal set of resources given the expected combination of costs, risk and uncertainty." For example, the UPSC asked for clarification on how the company's statement in Chapter 2 — "The emphasis of

the IRP is to determine the most robust resource plan under a reasonably wide range of potential futures as opposed to the optimal plan for some expected view of the future”—is consistent with this guideline. The UCCS states that they are not convinced of the optimality of the preferred portfolio. The UPSC and UAE believe that fixing resources for the CEM results in suboptimal resource selection. For example, the UAE states that the Group 2 portfolios appear to be suboptimal because the CEM was used to determine the build pattern of gas plants and front office transactions, while coal and wind resources were set. WRA, on the other hand, states that model results should not be used as an alternative to informed judgment and critical thinking.

Response: PacifiCorp agrees with WRA that modeling results should not be used as the sole basis for determining an optimal portfolio given the multi-objective and subjective nature of the resource planning exercise. PacifiCorp’s model solutions are dependent on model structure and the underlying assumptions. Thus, model results need to be interpreted in the light of real-world considerations. One of these considerations, cited in Chapter 7, are resource decision constraints resulting from new and expected state resource policies.

In the context of capacity expansion modeling with the CEM, any one model solution is only optimal for the single set of assumptions used for the associated model run and should not be considered optimal in any broader sense due to the deterministic nature of the model and the single set of input assumptions. In contrast, the role of the Planning and Risk model has been to determine the stochastic cost and risk impacts of alternative resource strategies, not to determine an optimal portfolio from a stochastic simulation standpoint. These two models together, with their different perspectives on the resource planning problem, and across a variety of input assumptions, have thus helped to support the overall resource decision.

In regard to the impact of fixing resources on model solution optimality, PacifiCorp points out that the main purpose of the CEM is to limit the set of potential resources to a manageable size for more detailed stochastic production cost analysis and to analyze alternative futures. The CEM was successfully used for this purpose. As discussed in Chapter 7, development of the Group 2 portfolios was informed by both Group 1 risk analysis results and resource policy considerations. CEM optimization was only used as a portfolio refinement tool; specifically, to evaluate the timing of the CCCT resources and select an optimized quantity of front office transactions resources to meet PacifiCorp’s annual load obligation and planning reserve.

Finally, PacifiCorp augmented its discussion on preferred portfolio selection in Chapter 7 by laying out the strategic justification for the portfolio. In essence, the company believes that its preferred portfolio represents a good balance of resource types with complementary strengths *that together* help to minimize resource risk. The idea of “robustness” under a reasonably wide range of potential futures reflects a decision goal to account for the possibility of various high-cost outcomes for customers and to avoid resource decisions that, in aggregate, lead to such an outcome being realized. The best way to accomplish this is through resource diversification, which the preferred portfolio proxy resources are intended to provide. Consequently, PacifiCorp’s definition of the optimal resource set is one that offers the best compromise of cost and risk when considering alternative futures and multiple stakeholder priorities. PacifiCorp notes that none of the state IRP standards provide definitive criteria for judging how a resource plan

for a multi-state utility has achieved optimality under risk and uncertainty, and given diverse resource preferences and policies among its state jurisdictions.

Planning Reserve Margin Selection and Resource Needs Assessment

A number of the parties disagreed with PacifiCorp’s use of a 12 percent planning reserve margin for its preferred portfolio, citing analysis results from the 2007 IRP that seem to support a higher margin. Others requested more justification for the selection decision. One party, UAE, endorsed the 12 percent planning reserve margin, stating that it has been adequately supported by PacifiCorp’s cost-risk tradeoff analysis. UAE also recommended further planning margin analysis including incorporating an assessment of market response to “high carbon risk, price caps, or other externalities.” The UPSC and UCCS requested an explanation of changes in certain capacity balance components relative to the components reported in the 2004 IRP, as well as cited inter-jurisdictional cost allocation issues associated with potential Energy Not Served.

Response: PacifiCorp expanded its discussion on the choice of a planning reserve margin in Chapter 7 (“Planning Reserve Margin Selection”). PacifiCorp’s position is that the planning reserve margin should not be considered an immutable constraint on the company’s resource decisions given a time of rapid public policy evolution and wide uncertainty over the resulting downstream cost impacts. Therefore, PacifiCorp now advocates a planning reserve *range* of 12 to 15 percent, and initially targets 12 percent for its preferred portfolio to develop some added planning flexibility as public policy continues to evolve and regional resource adequacy standards are addressed.

UPSC requested an explanation for the increase in wholesale sales reported in the 2007 IRP capacity balance relative to that reported in the 2004 and 2004 IRP Update balances. This change is due to a reporting change for the delivery portion of exchange contracts. Exchange contract deliveries are no longer reported in the Purchase and Renewable components as was done for the 2004 IRP and 2004 IRP Update. These delivery amounts now appear in the Sales component.

Inter-jurisdictional cost allocation issues are outside of the purview of the IRP process. This information will be provided as a separate response.

Relationship of PacifiCorp’s IRP with its Business Plan

A number of the Utah parties expressed concern about how PacifiCorp’s IRP is related to its Business Plan, and that PacifiCorp might not be meeting its IRP obligation under the Utah Standards and Guidelines to ensure that its business plan is “directly related to its Integrated Resource Plan.” (Procedural Issue no. 9) The UDPU also pointed out a lack of sufficient information that shows that the two plans are consistent, and suggests that PacifiCorp does not comply with the Standards and Guidelines on this basis.

Response: PacifiCorp’s Business Plan is directly related to the IRP; the business planning process is informed by the IRP resource analysis, the action plan, and subsequent procurement activities. Because the latest Business Plan was undergoing development during the latter half of the 2007 IRP cycle, it made sense to coordinate on certain resource assumptions. These assumptions are fully described in Chapter 7. Going forward, the 2007 IRP will be used to inform the next version of the Business Plan.

The 2007 IRP Action Plan

The UDPU believes that the draft IRP does not provide “detailed focus” on actions over the next two years as stated in Utah IRP standard 4(e). Areas that need more coverage include renewable portfolio standards, Klamath River hydroelectric relicensing, renewable resources, local renewable projects (MEHC commitment U33), and sulfur hexafluoride emissions control (MEHC commitment 42a).

Response: PacifiCorp believes that the level of detail on specific actions is comparable to what was provided in previous IRP action plans. This level of detail garnered no criticism from the UDPU in the past, and the company believes the level of detail is sufficient. Actions for acquiring up to 1,400 megawatts of cost-effective renewables are presented in the Renewables Action Plan, filed concurrently with this IRP in accordance with MEHC commitments.

Demand-Side Management

Comments centered on the lack of modeling of Class 2 (energy efficiency) programs, and the expectation that the forthcoming DSM potentials study will address parties’ concerns regarding benefit capture and market potential. The UDPU identified several issues: (1) a lack of data on Class 2 DSM, (2) concern that the IRP models “do not accurately reflect the costs and benefits associated with DSM resources”, citing the results of the CEM low and high DSM potential scenario results, (3) variable amounts of DSM and CHP resources were not subjected to risk analysis using the PaR model. The UDPU also requested that the company explain how the DSM potentials study results will be incorporated in the next IRP. The UCCS requested more explanation of the DSM resources included in the initial load and resource balance. The WRA expressed concern that an insufficient amount of DSM has been included in the IRP.

Response: PacifiCorp noted in the IRP report that Class 2 DSM could not be modeled in the CEM due to the lack of supply curve data for PacifiCorp’s service territory; rather, Class 2 DSM was treated as a decrement to the load forecast as in prior IRPs, while DSM decrement values determined using stochastic production cost modeling. A discussion of the handling of Class 2 DSM is provided in Chapter 6 (“Public Utility Commission Guidelines for Conservation Program Analysis in the IRP”).

For the DSM potentials study, the company will receive cost-supply curves for Class 1, Class 2, and Class 3 DSM programs, which will be input into the IRP models once they have been verified and approved for use. The company will also receive a set of CHP and customer-owned standby generator resource characterizations that will be included in the models as well.

Responding to the UDPU comment on performing manual DSM/CHP optimization using the stochastic PaR model, PacifiCorp notes that using the PaR in this manner is not practical given the long model run-times, which reach 16 to 18 hours. This limitation has been communicated to Utah parties during previous IRP cycles, and was one of the reasons why PacifiCorp acquired the CEM (to have an automated resource selection capability).

Regarding the UCCS request for more explanation on the DSM included in the load and resource balance, Table 4.10 in Chapter 4 summarizes existing DSM program contributions to the bal-

ance. Tables A.8 and A.15 in Appendix A outline the amounts and timing of Class 2 DSM load reductions. Expected Class 1 program contributions are described in Table A.13.

Market Reliance, Availability, and Price Risk

Several parties were concerned with the level of market purchases included in the preferred portfolio, and requested verification of market availability to support these amounts and other data and analysis. The UPSC requested that PacifiCorp provide supporting analysis of cost-risk tradeoffs of market reliance versus building resources. The RNP and NWEAC stated their concern that PacifiCorp overestimates the wholesale value of coal and other base load plants (and undervalues short-lead-time resources such as SCCTs and DSM) given the impact of emission performance standards and renewable portfolio standards.

Response: PacifiCorp added a new section in Chapter 7 that provides more information on the company's market purchase strategy and expected market availability.

Regarding analysis of cost-risk tradeoff analysis of market reliance versus building, PacifiCorp refers parties to a number of risk analysis portfolios and a sensitivity study designed to directly address the cost-risk tradeoffs of assets and market reliance. These results are documented in Chapter 7. For example, the section titled "Resource Strategy Risk Reduction" describes the comparison of portfolios with and without front office transactions after 2011. The chapter also describes a stochastic simulation study in which PacifiCorp replaced a 2012 base load resource with front office transactions.

PacifiCorp acknowledges and shares parties' concerns over the potential market impacts of new resource constraints imposed by renewable generation requirements and CO₂ emission performance standards. Action plan item no. 17 (Chapter 8, Table 8.2) addresses modeling enhancements to assist in the analysis of such issues. The company notes that such analysis capability is not present in existing market models that are designed to simulate integrated system operation. PacifiCorp has been exploring CEM customization possibilities with the model vendor, Global Energy Decisions.

Scope of Resource Analysis

Most of the parties identified resources that PacifiCorp did not model but thought it should have, or else requested an explanation for why they were not modeled. Examples include solar, geothermal, and storage technologies. The UCCS requested that PacifiCorp investigate an approach that enables comparable treatment of all technologies throughout the modeling process even if they have been excluded for modeling purposes on the basis of screening criteria. The UPSC questioned why the company is not addressing retrofits, retirements, and distributed technologies as resource options. The UDPU inquired as to PacifiCorp plans to build a landfill gas power plant in the near future. The UPSC and UCCS questioned why geothermal was not modeled given that it has the lowest reported total resource cost in Tables 5.3 and 5.4 (The UPSC also questioned the difference in geothermal capital costs between the value reported in the IRP and the Blundell economic study.) The WRA stated that technology risk should not be used as a screen to eliminate resources from further consideration, and also called for more robust analysis of CHP potential. The UAE recommended that the planning horizon be extended to facilitate analysis of nuclear and other long-lead-time resources. Both the NWEAC and WRA stated that the

CO₂ risk analysis was flawed by not including IGCC with carbon capture and sequestration as an appropriately modeled resource (i.e., allowing the CEM to select carbon capture and sequestration for an IGCC plant once it becomes economic to do so).

Response: A summary of the process for selecting resources to include in the IRP models is provided in Tables I.3 and I.4 in Appendix I (See the response to Oregon Guideline 1.a.1 in Table I.3, and the response to Utah Standard 4.b.ii in Table I.4). As noted, PacifiCorp intends to investigate a CEM modeling process that accommodates a broader range of technologies within the limitations of the company’s IRP models. PacifiCorp will consider retirements and retrofits as resource options in future IRPs. Consideration of these resource options and others will be made in the context of an overall review of resource potentials, data availability, technical feasibility, and modeling constraints.

Concerning the observation on the low reported geothermal total resource cost, PacifiCorp expanded its discussion on the geothermal project cost characterization and treatment of the renewable production tax credit for geothermal projects (Chapter 5, ‘Other Renewable Resources’). On the differences between reported geothermal capital costs in the IRP and Blundell economic study, PacifiCorp notes that the UCCS submitted a formal data request on May 16, 2007 on this issue, to which the company will respond separately from this IRP report.

Regarding the consideration of technology risk as a factor in resource screening, PacifiCorp points out this is just one factor that was used to develop the modeled resource list. PacifiCorp agrees that technology risk should not be used as a screen to exclude resources from further consideration. Other factors considered by the company included the outlook for commercial maturity during the 10-year investment horizon that was the focus of this IRP, and most importantly, practical modeling considerations of the CEM. PacifiCorp quickly approached the resource limit recommended by the model vendor and began to scale back resources and define generic proxy resources for front office transaction and renewables. The associated learning experience will be useful as the company addresses the anticipated expansion of resource options for the next IRP.

Regarding landfill gas plants, PacifiCorp has reviewed potential sites for such projects in the Rocky Mountain Power and Pacific Power service territories, and selected two sites in Oregon for which feasibility studies have been conducted. The initial findings and recommendation are undergoing review. The company is also looking at five other landfill sites (one in Washington and four in Utah) for possible feasibility analysis.

As to the UAE’s recommendation to extend the planning horizon to facilitate analysis of nuclear and other long-lead-time resources, the company will consider this change as it formulates its next IRP modeling plan.

Concerning the modeling of IGCC with carbon capture and sequestration, PacifiCorp notes that the current version of the CEM does not allow the modeling of plant retrofits such as carbon capture and sequestration. However, the company is acquiring a CEM model upgrade that includes this modeling capability, and expects to implement this functionality in time for the next IRP. Nevertheless, PacifiCorp disagrees with the WRA’s contention that the CO₂ risk analysis is inherently flawed to the extent that it “should be completely reworked before any conclusions must

be drawn” because of the way IGCC-based carbon capture and sequestration was addressed in the IRP models. PacifiCorp’s modeling of IGCC for this IRP first looked at the ability of carbon-capture-ready IGCC to stand on its own merits, and then performed various sensitivity analyses to investigate the potential cost impacts of adding carbon capture and sequestration. PacifiCorp believes that the uncertainties associated with carbon capture and sequestration are too great to consider it as an investment that customers and investors are willing to commit to and pay for in the period covered by the IRP action plan. The IGCC analyses performed by the company support the view that a decision to add IGCC to the company’s resource portfolio will not be driven by modeling considerations, but rather as an outcome of public policy debates and collaborative public-private development ventures such as the one recently announced by the Wyoming Infrastructure Authority and PacifiCorp.

Load Forecast

A number of parties requested additional explanation for why the March 2007 Utah load forecast shows a dip in the growth in 2008-2009 relative to the May 2006 forecast. The UCCS requested justification for why PacifiCorp relies on an expected (1 in 2) load forecast for planning, and inquires as to how planning to a 90% confidence interval would change the company’s resource position and resource selection decisions. Regarding the higher load growth expected for Wyoming, the WRA expressed concern about committing resources to uncertain and volatile extractive industry loads, which account for the higher forecasted load growth. The UPSC requested the insertion of additional load forecast information in the IRP report.

Response: PacifiCorp accounts for load forecast error in its IRP by using a planning reserve margin. Planning to a 90 percent confidence interval would lessen the need to plan for unexpected load growth and, therefore, would likely reduce the level of planning reserve margin required by the company.

PacifiCorp is well aware of the volatile nature of extractive industry loads, and therefore applies a discount factor to the load forecasts contained in industrial customer service requests. Forecasts for the new Wyoming loads were reduced by 30 percent compared to estimates provided by customers. The load discount is based on rankings of the likelihood of occurrence of the customers’ loads and the probability associated with that likelihood. Additionally, the company looks at the market conditions that will impact each industry, supply and demand in the industry, and other events that may impact the industry such as substitution impacts.

Concerning the requested load forecast information, PacifiCorp made the following report modifications to Chapter 4 and Appendix A:

- Data for 2006 was added to both the energy and coincident peak capacity forecasts tables in Chapter 4, as well as to each state table in Appendix A.
- A column was added to Table 4.5 in Chapter 4 that shows loads for the Southeast Idaho region.
- A new section, “Jurisdictional Peak Load Forecast,” was added in Chapter 4 with information similar to that reported for the coincident peak.
- An explanation for the Utah load growth dip was added to Chapter 4 (“May 2006 Load Forecast Comparison”).

Carbon Dioxide Regulatory Risk Analysis

The WRA cited a number of concerns with PacifiCorp’s CO₂ risk modeling approach. First, they questioned the value of using a \$0/ton CO₂ cost adder and cited the \$8/ton medium adder case as also “remote over the long term.” They advocate studying carbon costs in the range of plus or minus \$30/ton. Second, they view the use of a year-2000 emissions cap under a cap-and-trade mechanism as unrealistic. Third, they believe that adding two coal resources by 2014 does not provide sufficient diversity to endure future carbon regulation. Fourth, they question PacifiCorp’s treatment of CO₂ regulation as a scenario risk and propose that the company model it probabilistically. The UAE claims that PacifiCorp failed to capture the impact of higher gas prices and lower electricity demand attributable to potentially high carbon taxes. The RNP views PacifiCorp’s greenhouse gas mitigation strategy as “insufficient for the task,” and “is hardly an active strategy at all.” The RNP also faults PacifiCorp for not modeling a portfolio that decreases overall CO₂ emissions, or that has no coal resources.

Response: PacifiCorp is required, via the Oregon IRP Standards and Guidelines, to assess environmental externality costs using a \$0/ton CO₂ cost adder. Also, UPSC staff requested that the company include the \$0 adder as part of a business-as-usual scenario case. The use of a single point estimate of around \$30/ton, if that is what is being suggested, is not consistent with Oregon or Utah IRP guidelines that call for a number of specific adder values (in the case of Oregon) or a range of estimated external costs (in the case of Utah). PacifiCorp models a \$38/ton adder (in 2008 dollars). Regarding the baseline cap and other assumptions for specifying a CO₂ regulatory framework, the company will revisit them as part of its next IRP process and as a result of the outcome of the Oregon Public Utility Commission proceeding on CO₂ risk in the IRP (Docket UM 1302). PacifiCorp does not understand WRA’s point regarding the use of stochastic methods to model CO₂ regulatory risks. WRA supports stochastic analysis over scenario analysis, but then concedes that stochastic analysis is too complicated and should therefore be discounted or abandoned in favor of informed judgment. From this logic, PacifiCorp is not clear what modeling approach the WRA finds acceptable for conducting CO₂ risk analysis.

Regarding the claim that the company has not captured gas price risk due to higher carbon taxes, PacifiCorp notes that the gas price and electricity price forecasts used for the CO₂ cost adder scenarios account for the increased CO₂ adder values. See the text box titled “Modeling the Impact of CO₂ Externality Costs on Forward Electricity Prices” in the Environmental Externality Cost section of Chapter 6.

Finally, PacifiCorp updated Chapter 7 of the draft IRP report with a portfolio study that entailed constraining CEM system-wide resource selection to only those resources that could meet a California-style greenhouse gas emission performance standard. One of the resource choices was IGCC with carbon capture and sequestration.

Transmission

The UDPU had several transmission questions. First, they question whether transmission wheeling as a potential solution to transmission needs is appropriate given that it “fluctuates with the market”. The UDPU also stated that the IRP draft does not address renewable portfolio standard (RPS) impacts on transmission planning or the National Governor’s Conference positions on transmission planning and resources, and asks if these issues are being considered. Finally, they

asked for clarification on the use of 500-megawatt blocks for specifying certain transmission paths in the CEM (Bridger-Ben Lomond; Mona-Utah North; Wyoming-Bridger East; Utah North-West Main; Utah South-Four Corners). The UAE expressed support for the use of transmission additions to delay supply-side resources, but was not clear if transmission was put on an equal footing with generation.

Response: PacifiCorp’s view is that it is prudent to include all reasonable transmission options for consideration given the complexities associated with building transmission facilities. Regarding RPS requirements, the company is investigating the consequences of these new regulations.

Regarding specification of the above referenced transmission resources, these resources are considered as proxies for a variety of potential projects to support new generation and facilitate power transfers in the east control area. Specifying 500-megawatt blocks for a proxy transmission resource was an efficient method to express incremental transmission investment for the CEM to select.

Transmission resources were treated on a comparable basis with respect to generation resources. The CEM makes decisions to build generation or transmission units at a given resource site in a given year. The amortized cost of both transmission and generation capacity expansion is included in the model’s PVRR minimization objective function.

Miscellaneous

Two parties, NWECA and the RNP, advocated that the company rely on an upper-tail measure of stochastic risk rather than risk exposure (stochastic upper-tail mean PVRR minus the overall stochastic mean PVRR for 100 Monte Carlo model iterations).

The RNP states that the IRP does not adequately consider the capital cost risks of pulverized coal plants, and cites one example of a coal plant construction estimate that increased by 50 percent over original estimates.

Regarding the Intermountain Power Plant Unit 3 project (IPP 3), the UDPU requested a status update and an indication of the company’s current intentions regarding the project. The WRA also believes that an in-service date of 2012 for IPP3 or any other coal plant is unrealistic.

The UPSC requested detailed information on the company’s commitment to invest \$1.2 billion on cost-effective pollution control. Specific requests include the following:

- Explanation of “how and in what forum the Company plans to perform the cost-benefit analysis for these investments, and should such analysis be part of the Integrated Resource Planning evaluation?”
- Does the \$1.2 billion include mandatory requirements, i.e., mercury control on existing plants?
- Does it include those existing plant retrofit projects which are necessary for permit requirements to add new units at facilities?
- Clarify and provide a table showing the value, project description, and location of the investments.

Response: PacifiCorp has added the upper-tail mean along with the 95th percentile in the Chapter 7 tables that report stochastic risk measures for the risk analysis portfolios. The company notes that risk analysis portfolio rankings are generally invariant with respect to the stochastic risk measures.

PacifiCorp has been tracking construction costs for all new resource types, and has seen increases in costs for all resources. This fact is mentioned in Chapter 5. The company will use the bid information received for its Base Load Request For Proposal to help inform estimation of new resource capital costs for the 2007 IRP Update.

Regarding the status of IPP 3, PacifiCorp and the other Intermountain Power Plant Unit 3 (IPP 3) participants acknowledge that there are some air permit challenges by certain parties and contractual complications associated with Los Angeles Department of Water and Power that need to be resolved. PacifiCorp and the IPP 3 development team remain focused on working through these issues and intend to exercise their development right relating to construction of the facility. The IPP 3 development team is currently evaluating bids from major engineering procurement and construction contractors. IPP 3 remains a component in filling PacifiCorp's needs for low cost reliable resources, and the plant remains as a benchmark resource for 2012.

The UPSC's request for PacifiCorp's pollution control investment plans will be provided as a separate response.

CONTACT INFORMATION

PacifiCorp's IRP internet website contains many of the documents and presentations that support the 2003, 2004 and 2007 Integrated Resource Plans. To access it, please visit the company's website at <http://www.PacifiCorp.com>, click on the menu "News & Info" and select "Integrated Resource Planning".

PacifiCorp requests that any informal request be sent in writing to the following address or email address below.

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APPENDIX G – PERFORMANCE ON 2004 IRP ACTION PLAN

INTRODUCTION

This appendix summarizes the performance on the 2004 IRP action plan filed in January 2005. PacifiCorp provided an update of this action plan in November 2005 as part of the “2004 IRP Update” filed with state commissions in November 2005. The 2004 IRP Update action plan also incorporated updates to several action items in the 2004 IRP action plan. Table G.1 shows the progress of the original and updated action items listed in Table 5.2 of the 2004 IRP Update document (Chapter 5, page 46).

Table G.1 – Status Update on 2004 IRP Action Plan

Action Item	Addition Type	Resource Type	Timing	Size (Rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	2004 IRP Action Plan Description	Status
1	Supply-Side	Renewables	FY 2006 - 2015	1,400	System	Wind	Continue to aggressively pursue cost-effective renewable resources through current and future RFP(s).	PacifiCorp has acquired 346 megawatts of the 400 megawatt target set for 2007, as of April 2007. The company plans to acquire all 1,400 megawatts by 2010, and to acquire an additional 600 megawatts from 2011 through 2013.
2	DSM	Class 2	FY 2006 - 2015	450 MWa	System	100 MW decrements at various load shapes	Use decrement values to assess cost-effective bids in DSM RFP(s). Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and up to an additional 200 MWa if cost-effective programs can be found through the RFP process.	<ul style="list-style-type: none"> The company conducted a class 2 DSM decrement study for the 2007 IRP. To address risk, this study used stochastic simulation with an \$8/ton CO₂ adder. PacifiCorp also increased the number of load shapes from eight to twelve. The 2005 DSM RFP to procure Class 1, 2 and 3 resources was issued according to the action plan in the 2004 IRP (reference Table 9.3). The RFP was structured to solicit proposals for both specific resource types: a comprehensive residential equipment and service program as well as an “all comers” request for each resource type. The Home Energy Savers program was filed and approved in 2006 in Idaho, Washington and Utah and is being proposed in California and Wyoming in 2007. On March 20, 2007, the Utah Public Service Commission approved modifications to the

Action Item	Addition Type	Resource Type	Timing	Size (Rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	2004 IRP Action Plan Description	Status
								<p>2007 Energy Star New Homes Program and in April 2007 extended the Cool Cash air conditioner efficiency program.</p> <ul style="list-style-type: none"> The company also accepted a proposal to enhance business program penetration of the new construction market. In addition, one program proposal from the 2005 DSM RFP is still under consideration. It will be evaluated further using updated valuation information derived through the 2007 IRP planning process as well as results from the system-wide DSM potential study results due in June 2007.
3	Distributed Generation	CHP	FY 2010 (summer of CY 2009) and FY 2013 (CY 2012)	n/a	System	Two 45 MW units using NREL cost estimates	Include CHP as eligible resources in supply-side RFPs.	<p>Continue to purchase CHP output as Qualifying Facilities (QF) pursuant to PURPA regulations. The 2007 preferred portfolio contains an additional 100 MW of CHP resources, cited in 2007 IRP action plan item no. 5.</p>
4	Distributed Generation	Standby Generators	FY 2010 (summer of CY 2009) and FY 2013 (CY 2012)	n/a	Utah	75 MW in Utah	Include a provision for Standby Generators in supply-side RFPs. Investigate, with Air Quality Officials, the viability of this resource option.	<p>The final Base Load RFP does not contain an East side stand-by generation resource exception due to Utah Division of Air Quality regulations on diesel generation emissions standards. PacifiCorp will continue to investigate alternatives for stand-by generators as a resource. PacifiCorp met with Portland General Electric to discuss their stand-by generation program.</p>

Action Item	Addition Type	Resource Type	Timing	Size (Rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	2004 IRP Action Plan Description	Status
5	DSM	Class 1	FY 2009 (summer of CY 2008)	50	Utah	Irrigation Load Control	Procure cost-effective summer load control program in Utah by the summer of 2008.	The company launched a commercial lighting control program (Load Lightener) in Utah in February 2005. However, the program was terminated in August 2006 due to poor program performance. The company expanded the Idaho irrigation load management program and extended the Idaho irrigation load management program into Utah in the spring of 2007, and continues to investigate the possible expansion of Utah's air conditioner load control program beyond 100 MW's (at the generator). In addition, the company is still evaluating, within the 2007 planning process, two other Class 1 proposals received through the 2005 DSM RFP. Like the Class 2 proposal, the company will utilize the system-wide DSM potential study results to help further assess the viability of the remaining proposals.
6	DSM	Class 1	FY 2009 (summer of CY 2008)	50	OR/WA/CA	Irrigation Load Control	Procure cost-effective summer load control program in Oregon, Washington, and/or California by the summer of 2008.	The 2005 DSM RFP generated Class 1 load control proposals targeting our western system. The proposals were of various sizes and were significantly more expensive than anticipated. The proposals underwent further analysis within the 2007 IRP modeling process and were determined not to be cost-effective. However, the 2007 IRP modeling did select the lesser cost irrigation load management pro-

Action Item	Addition Type	Resource Type	Timing	Size (Rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	2004 IRP Action Plan Description	Status
7	Transmission	Path-C Upgrade	FY2011 (summer of CY 2010)	300	ID / UT	Path-C Upgrade	Pursue upgrade of transfer capability from Idaho to Utah.	Path C transmission service requests have been completed for the system impact studies and are currently under the Facility Study phase. Grid West was dissolved as of June 2006. Other regional entities continue to pursue regional transmission planning initiatives. Please see Chapter 3 for additional transmission related topics.
8	Supply-Side	Coal resource	FY 2013 (summer of CY 2012)	600	Utah	Pulverized Coal Plant	Procure a high capacity factor resource in or delivered to Utah by the summer of CY 2012.	The Base Load RFP was issued on April 5, 2007 for up to 1,700 MW for delivery in 2012, 2013, and/or 2014. The company is currently in the bidder submission phase of the RFP process. The RFP contains two benchmark coal plants and an IGCC option for bidders. Resources for 2012 and 2014 are being requested with exceptions for load curtailment and Qualifying Facility contracts.
9	Transmission	Regional Transmission	FY 2013 and beyond	n/a	System	Transmission from Wyoming to Utah	Continue to work with other regional entities to develop Grid West. Continue to actively participate in regional transmission initiatives (e.g. RMATS, NTAC)	PacifiCorp is engaged in a number of regional transmission planning initiatives intended to address transmission issues and opportunities. WECC recently launched the Transmission Expansion Planning Policy Committee (TEPPC) to address interconnection-wide transmission expansion planning. Grid West was dissolved as of June 2006. A group called the Northern

Action Item	Addition Type	Resource Type	Timing	Size (Rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	2004 IRP Action Plan Description	Status
10	IRP Process	Modeling	2007 IRP	n/a	n/a	n/a	Incorporate Capacity Expansion Model into portfolio and scenario analysis.	<p>Tier Transmission Group was formed to facilitate regional planning in the absence of Grid West and the Rocky Mountain Area Transmission Study (RMATS). Please see Chapter 3 for additional transmission related topics.</p> <p>PacifiCorp placed the Capacity Expansion Module (licensed by Global Energy Decisions Inc.) into full production for the 2007 IRP process. See Chapters 6 and 7 for more information on how this tool was used in the 2007 IRP.</p>

APPENDIX H – DEFERRAL OF DISTRIBUTION INFRASTRUCTURE WITH CUSTOMER-BASED COMBINED HEAT AND POWER GENERATION

INTRODUCTION

As part of Oregon Order 06-029, PacifiCorp was asked to examine the potential for customer-based high-efficiency combined heat and power (CHP) resources to defer investment in the distribution system to meet load growth. The specific situation the company was ordered to examine was a case where a customer utilizing CHP, sized to exactly meet the customer load, would be connected to the distribution system as normal, but no additional infrastructure would be added to accommodate the additional load. In the event of an outage to the generation, the customer would be served by PacifiCorp's distribution system, as long as capacity was available; if this outage occurred at a time where the distribution infrastructure was incapable of serving the additional load for whatever reason, the customer would be automatically disconnected.

The intent of this appendix is to first determine what distribution infrastructure deferrals would be possible for an interruptible customer with on-site generation as described above, and then to compare the cost of those deferrals to a traditional customer taking firm service and having no on-site generation. For the purposes of the comparison, it is assumed that five megawatts of customer load is to be added to PacifiCorp's west control area 12.5 kilovolt distribution system (either a new load or a customer adding load).

TRADITIONAL CONNECTION

Extending service to a five megawatt customer to the company's distribution system is a typical industrial new connection for PacifiCorp, a request which occurs many times per year. Generally a customer receives an allowance for their connection facilities equal to one year's expected revenue; any expenditure beyond this is an out-of-pocket expense for the customer. For a customer of this size, these connection requirements typically range from \$50,000 to \$150,000, not inclusive of upstream reinforcements necessary to accommodate new load. The expected revenue for a five megawatt, primary-metered customer ranges from \$400,000 to \$600,000 per year, which means that usually all of the cost is borne by PacifiCorp. The upstream reinforcements can range from \$500,000 for new feeder infrastructure to more than \$2,500,000 if an additional substation is required. These are also at the company's expense.

The total cost of adding a new five megawatt customer is estimated to range from \$550,000 to \$2,650,000 in this example. All of these connection expenses are considered capital improvements and are depreciated over 50 to 60 years, depending on the type of facility.

GENERATION CONNECTION

If a customer decides to serve its electricity needs with an on-site generating facility, along with being interrupted when their own generating facility is down, then the company would not ex-

pect any revenues. Therefore, the company would not pay any connection costs for this customer and would save \$50,000 to \$150,000 of interconnection costs describe above.

Additionally, because this customer would be interruptible if the existing distribution infrastructure could not serve the customer for some reason (under-voltage, over-current, etc.) during a generator outage, no additional infrastructure would be necessary. This may allow the company to defer the \$500,000 to \$2,500,000 investment previously identified, depending on the current loading levels on the feeder. For example, PacifiCorp rates its 12.5 kilovolt circuits for approximately ten megawatts, or twice the load that is expected to be added as a result of this customer connection. Therefore, any feeder already loaded to 50 percent or more of its rating would need to be upgraded in order to provide traditional service to this particular customer. Feeders loaded below this threshold would not require upgrade. Examining Oregon’s feeder population, we find that about 61 percent of PacifiCorp Oregon circuits are currently loaded at or above 50 percent. If the five megawatt customer were to be located on one of these feeders, then there could be deferred investment of \$500,000 to \$2,500,000. If the five megawatt customer were to be located on one of these feeders, then there could be deferred investment of \$500,000 to \$2,500,000. PacifiCorp would not realize any additional capital investment savings for customers located on the other 39 percent of feeders.

CONCLUSION

The comparison above shows that a five megawatt load, coupled with a five megawatt customer-sited generation unit (customer-owned or not) located on a typical 12.5 kilovolt feeder in Oregon can potentially offset estimated connection costs of \$50,000 to \$150,000 under current line extension policies. In addition, there may be an opportunity to avoid infrastructure costs, at an estimated amount of \$500,000 to \$2,500,000. These savings would only be available if the customer agreed to be interrupted when their generation is reduced or off-line, and the distribution system is not capable of being used to serve their load. Actual savings, if any, from a customer in a situation similar to the one described in this example, would be based on their particular circumstances.

APPENDIX I – IRP REGULATORY COMPLIANCE

BACKGROUND

Least-cost planning (i.e., Integrated Resource Planning) guidelines were first imposed on regulated utilities by state commissions in the 1980s. Their purpose was to require utilities to consider all resource alternatives, including demand-side measures, on an equal comparative footing, when making resource planning decisions to meet growing load obligations. Integrated resource planning has expanded since then to incorporate the consideration of risk, uncertainty, and environmental externality costs into the resource evaluation framework. Planning rules were also intended to require utilities to involve regulators and the general public in the planning process prior to making resource decisions.

PacifiCorp prepares an IRP for the states in which it provides retail service. While the rules among the jurisdictional states vary in substance and style concerning IRP submission requirements, there is a consistent thread in intent and approach. PacifiCorp is required to file an IRP every two years with most state commissions. The IRP must look at all resource alternatives on a level playing field and propose a near-term action plan that assures adequate supply to meet load obligations at least cost, while taking into account risks and uncertainties. The IRP must be developed in an open, public process and give interested parties a meaningful opportunity to participate in the planning.

This appendix provides a discussion on how the 2007 IRP complies with the various state commission IRP Standards and Guidelines, 2004 IRP acknowledgement requirements, and other commission decisions. Included at the end of this appendix are the following tables:

- Table I.1 – Provides an overview and comparison of the rules in each state for which IRP submission is required.³
- Table I.2 – Provides a description of how the 2004 IRP acknowledgement requirements and other commission requests were addressed.
- Table I.3 – Provides an explanation of how this plan addresses each of the items contained in the new Oregon IRP guidelines issued in January 2007.
- Table I.4 – Provides an explanation of how this plan addresses each of the items contained in the Utah Public Service Commission IRP Standard and Guidelines issued in June 1992.

GENERAL COMPLIANCE

PacifiCorp prepares the IRP on a biennial basis and files the IRP with the state commissions. The preparation of the IRP is done in an open public process with consultation between all interested parties, including commissioners and commission staff, customers, and other stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process, and also serves to inform all parties on the planning issues and

³ California and Wyoming requirements are not summarized in Table I.1. The Wyoming requirements are discussed in the chapter text. California guidelines exempt a utility with less than 500,000 customers in the state from filing an IRP.

approach. The public input process for this IRP, described in Volume 1, Chapter 2, as well as in Appendix F, fully complies with the IRP Standards and Guidelines.

The IRP provides a framework and plan for future actions to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP evaluates, over a twenty-year planning period, the future loads of PacifiCorp customers and the capability of existing resources to meet this load.

To fill any gap between changes in loads and existing resources, the IRP evaluates all available resource options, as required by state commission rules. These resource alternatives include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Chapters 6 and 7, meets this requirement and includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of numerous risks, uncertainties and externality costs that could occur. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western Interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP Standards and Guidelines, and is described at a high level in Chapter 2 and in greater detail in Chapter 6.

The IRP analysis is designed to define a resource plan that is least cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual CO₂ emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Chapter 7.

Consistent with the IRP Standards and Guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan (See Chapter 8). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. Appendix G provides a progress report that relates the 2007 IRP Action Plan with those provided in the 2004 IRP and 2004 IRP Update.

The 2007 IRP and the related Action Plan are filed with each commission with a request for prompt acknowledgement. Acknowledgement means that a commission recognizes the IRP as meeting all regulatory requirements at the time the acknowledgement is made. In the case where a commission acknowledges the IRP in part or not at all, PacifiCorp works with the commission to modify and re-file an IRP that meets acknowledgement standards.

State commission acknowledgement orders or letters typically stress that an acknowledgement does not indicate approval or endorsement of IRP conclusions or analysis results. Similarly, an acknowledgement does not imply that favorable ratemaking treatment for resources proposed in the IRP will be given.

California

Subsection (i) of California Public Utilities Code, Section 454.5, states that utilities serving less than 500,000 customers in the state are exempt from filing an Integrated Resource Plan for California. PacifiCorp serves only 42,000 customers in the most northern parts of the state. PacifiCorp filed for and received an exemption on July 10, 2003.

Idaho

The Idaho Public Utilities Commission's Order No. 22299, issued in January 1989, specifies integrated resource planning requirements. The Order mandates that PacifiCorp submit a Resource Management Report (RMR) on a biennial basis. The intent of the RMR is to describe the status of IRP efforts in a concise format, and cover the following areas:

Each utility's RMR should discuss any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand and supply side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.

This IRP is submitted to the Idaho PUC as the Resource Management Report for 2007, and fully addresses the above report components. The IRP also evaluates DSM using a load decrement approach, as discussed in Chapters 6 and 7. This approach is consistent with using an avoided cost approach to evaluating DSM as set forth in IPUC Order No. 21249.

Oregon

This IRP is submitted to the Oregon PUC in compliance with its new planning guidelines issued in January 2007 (Order No. 07-002). These guidelines supersede previous ones, and many codify analysis requirements outlined in the Commission's acknowledgement order for PacifiCorp's 2004 IRP.

The Commission's new IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), and resource acquisition (Guideline 13). Consistent with the earlier guidelines (Order 89-507), the Commission notes that acknowledgement does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given. Table I.3 provides considerable detail on how this plan addresses each of the requirements.

Utah

This IRP is submitted to the Utah Public Service Commission in compliance with its 1992 Order on Standards and Guidelines for Integrated Resource Planning (Docket No. 90-2035-01, "Report and Order on Standards and Guidelines"). Table I.4 documents how PacifiCorp complies with each of these standards.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring least cost planning (Washington Administrative Code 480-100-238), and the rule amendment issued on January 9, 2006 (WAC 480-100-238, Docket No. UE-030311). In addition to a least cost plan, the rule requires provision of a two-year action plan and a progress report that “relates the new plan to the previously filed plan.”

The rule amendment also now requires PacifiCorp to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, the resource assessment method, and timing and extent of public participation. PacifiCorp filed a work plan with the Commission on February 21, 2006, and had a follow-up conference call with WUTC staff to make sure the work plan met staff expectations.

Finally, the rule amendment now requires PacifiCorp to provide an assessment of transmission system capability and reliability. This requirement was met in this IRP by modeling the company’s current transmission system along with both generation and transmission resource options as part of its resource portfolio analyses. These analyses used such reliability metrics as Loss of Load Probability and Energy Not Served to assess the impacts of different resource combinations on system reliability. The stochastic simulation and risk analysis section of Chapter 7 reports the reliability analysis results.

Wyoming

On October 4, 2001, the Public Service Commission of Wyoming issued an Order and Stipulation requiring PacifiCorp to file annual resource planning and transmission reports for a three-year time period beginning in 2002, each to be submitted on March 31. Each report “will address (1) load and resource planning issues affecting Wyoming, and (2) transmission investment, operation and planning issues affecting Wyoming.” PacifiCorp submitted its last report in March 2004.

Table I.1 – Integrated Resource Planning Standards and Guidelines Summary by State

Topic	Oregon	Utah	Washington	Idaho
Source	Order 89-507 <i>Least-cost Planning for Resource Acquisitions</i> , April 20, 1989. Order No. 07-002, <i>Investigation Into Integrated Resource Planning</i> , January 8, 2007.	Docket 90-2035-01 <i>Standards and Guidelines for Integrated Resource Planning</i> June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 <i>Least Cost Planning Rule-making</i> , January 9, 2006 (Docket # UE-030311)	Order 22299 <i>Electric Utility Conservation Standards and Practices</i> January, 1989.
Filing Requirements	Least-cost plans must be filed with the Commission.	An Integrated Resource Plan (IRP) is to be submitted to Commission.	Submit a least cost plan to the Commission. Plan to be developed with consultation of Commission staff, and with public involvement.	Submit “Resource Management Report” (RMR) on planning status. Also file progress reports on conservation and low-income programs.
Frequency	Plans filed biennially. Interim reports on plan progress also required (informational filing only). Order 07-002 requires IRP filing within two years of its previous IRP acknowledgement order.	File biennially.	File biennially.	RMP to be filed at least biennially. Conservation reports to be filed annually.
Commission response	Least-cost plan (LCP) <i>acknowledged</i> if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgement order is issued. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP <i>acknowledged</i> if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.

Topic	Oregon	Utah	Washington	Idaho
Process	<p>The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07-002 requires that the utility present IRP results to the OPUC at a public meeting prior to the deadline for written public comments. Commission staff and parties should complete their comments and recommendations within six months after IRP filing.</p> <p>Competitive secrets must be protected.</p>	<p>Planning process open to the public at all stages. IRP developed in consultation with the Commission, its staff, with ample opportunity for public input.</p>	<p>In consultation with Commission staff, develop and implement a public involvement plan. Involvement by the public in development of the plan is required. For the amended rules issued in January 2006, PacifiCorp is required to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, resource assessment method, and timing and extent of public participation.</p>	<p>Utilities to work with Commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.</p>
Focus	<p>20-year plan, with end-effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs.</p>	<p>20-year plan, with short-term (four-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed. The IRP process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.</p>	<p>20-year plan, with short-term (two-year) action plan. The plan describes mix of resources sufficient to meet current and future loads at “lowest reasonable” cost to utility and ratepayers. Resource cost, market volatility risks, demand-side resource uncertainty, resource dispatchability, ratepayer risks, policy impacts, and environmental risks, must be considered.</p>	<p>20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility.</p>
Elements	<p>Basic elements include:</p> <ul style="list-style-type: none"> • All resources evaluated on a consistent and comparable basis. • Risk and uncertainty must be considered. • The primary goal must be least cost, consistent with the 	<p>IRP will include:</p> <ul style="list-style-type: none"> • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis. 	<p>The plan shall include:</p> <ul style="list-style-type: none"> • A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electricity 	<p>Discuss analyses considered including:</p> <ul style="list-style-type: none"> • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options;

Topic	Oregon	Utah	Washington	Idaho
	<p>long-run public interest.</p> <ul style="list-style-type: none"> ● The plan must be consistent with Oregon and federal energy policy. ● External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). ● Identify acquisition strategies for action plan resources, assess advantages/disadvantages of resource ownership versus purchases, and identify benchmark resources considered for competitive bidding. ● Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. ● Avoided cost filing required within 30 days of acknowledgement. 	<ul style="list-style-type: none"> ● Analysis of the role of competitive bidding ● A plan for adapting to different paths as the future unfolds. ● A cost effectiveness methodology. ● An evaluation of the financial, competitive, reliability and operational risks associated with resource options, and how the action plan addresses these risks. ● Definition of how risks are allocated between ratepayers and shareholders ● DSM and supply side resources evaluated at “Total Resource Cost” rather than utility cost. 	<p>cal end-uses.</p> <ul style="list-style-type: none"> ● An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. ● Assessment of a wide range of conventional and commercially available nonconventional generating technologies ● An assessment of transmission system capability and reliability (Added per amended rules issued in January 2006). ● A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using “lowest reasonable cost” criteria. ● Integration of the demand forecasts and resource evaluations into a long-range (at least 10 years) plan. ● All plans shall also include a progress report that relates the new plan to the previously filed plan. 	<ul style="list-style-type: none"> ● Contingencies for upgrading, optioning and acquiring resources at optimum times; ● Report on existing resource stack, load forecast and additional resource menu.

Table I.2 – Handling of 2004 IRP Acknowledgement and Other IRP Requirements

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
ID	Staff recommends that PacifiCorp continue to evaluate and investigate IGCC in its next IRP. (Acceptance of Filing, Case No. PAC-E-05-2, p. 6)	PacifiCorp incorporated various IGCC resources, distinguished by location and technology configuration (including CO ₂ capture and sequestration), in its capacity expansion optimization and stochastic modeling studies. Chapter 7 describes the IGCC modeling results.
ID	As we indicated in our acceptance of the Company’s 2003 Electric IRP filing, in addition to being apprised through periodic status reports of supply resources the Company is actually building or contracting for and demand side programs the Company is implementing, the Commission expects to receive periodic updates as to the Company’s specific plans for issuing requests for proposals (RFPs). (Acceptance of Filing, Case No. PAC-E-05-2, p. 7)	PacifiCorp provided the Idaho Public Utility Commission procurement updates on April 12 and August 30, 2006, and plans to provide them on a quarterly basis.
OR	Use decrement values to assess cost-effective bids in DSM RFP(s). Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and 200 MWa or more of additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth, and as approved by each State’s Commission. (Action Item 1 revision, OPUC Order 06-029, p. 60)	See the “Class 2 Demand-side Management Decrement Analysis” section in Chapter 7 for updated decrement values. See the “Existing Resources” section of Chapter 4 for an update on the progress of Class 2 DSM programs, as well as Appendix G, “Action Plan Status”.
OR	Execute an agreement with the Energy Trust of Oregon, as soon as possible, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable timely completion of resource agreements with the recent extension of the federal production tax credit. (Additional Action Item, OPUC Order 06-029, p. 60)	A master agreement to fund the above-market costs of new renewable energy resources was signed on April 6, 2006.

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
OR	For the next IRP or Action Plan, develop supply curves for various types of Class 1 DSM resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. Evaluate this approach for Class 2 DSM resources and recommend whether this approach is preferable to the current decrement approach. (Additional Action Item, OPUC Order 06-029, p. 60)	PacifiCorp used Class 1 DSM proxy supply curves, developed by Quantec LLC, for portfolio optimization modeling using the Capacity Expansion Module. See Appendix B for the complete Quantec DSM study. Chapter 5 outlines the supply curves used in the CEM. For Class 2 DSM, the company chose to continue using the decrement approach for the 2007 IRP, but enhanced it by adopting stochastic simulation to capture risk. PacifiCorp’s plan to use decrement analysis was presented and discussed at the February 10, 2006 technical workshop on demand-side management.
OR	For the next IRP or Action Plan, assume existing interruptible contracts continue unless they are not renegotiable or other resources would provide better value. (Additional Action Item, OPUC Order 06-029, p. 60)	PacifiCorp adopted the assumption that existing interruptible contracts are extended until beyond the end of the 20-year IRP study period.
OR	For the next IRP or Action Plan, assess IGCC technology in a location potentially suitable for CO ₂ sequestration, including cost, commercialization status, technology risk, and comparative performance under future uncertainties, including market prices and CO ₂ regulation. (Additional Action Item, OPUC Order 06-029, p. 61)	PacifiCorp included several IGCC plant configurations and locations as resource options in its “alternative future” scenario modeling, including one with carbon capture and sequestration. IGCC resources were also included in risk analysis portfolios for stochastic simulation. See “Resource Options” in Chapter 5 for IGCC cost and performance characteristics. See Chapter 7 for IGCC modeling results.
OR	For the next IRP or Action Plan, analyze the costs and risks of portfolios that include various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission. (Additional Action Item, OPUC Order 06-029, p. 61)	PacifiCorp included various transmission resources in its capacity optimization model. For a CEM sensitivity study, the company included a proxy resource representing the Frontier Line project, reflecting a strategy to access markets in California and the southwest U.S. See “Resource Expansion Alternatives” in Chapter 5 for details on the transmission resources modeled, and Chapter 7 for modeling results.

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
OR	Conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in PacifiCorp’s service area over the IRP study period, and assess how the Company’s base and planned programs compare with the cost-effective amounts determined in the study. (New IRP requirement, OPUC Order 06-029, p. 61)	Due to the timing of OPUC’s 2004 acknowledgment Order (in January 2006), and as agreed to by OPUC staff, this requirement is being met via the MEHC commitment to perform a multi-state DSM potentials study to be completed by June 2007. Development and use of Quantec’s proxy DSM supply curves was intended as a compromise strategy until the DSM potentials study becomes available for use in the next IRP.
OR	Determine the expected load reductions from Class 3 DSM programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio options that compete with supply-side options. (New IRP requirement, OPUC Order 06-029, p. 61)	PacifiCorp incorporated supply curves into its portfolio modeling for the following Class 3 DSM resources: Curtailable Rates, Demand Buyback, and Critical Peak Pricing. See Chapter 4 and Appendix B for details.
OR	Evaluate loss of load probability, expected unserved energy, and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. (New IRP requirement, OPUC Order 06-029, p. 61)	PacifiCorp included these supply reliability metrics as part of its stochastic portfolio risk analysis. The Planning and Risk Module (PaR) 12-percent capacity reserve margin sensitivity study included the maximum available amount of Class 3 DSM as indicated by the Quantec proxy supply curves.
OR	Evaluate alternatives for determining the expected annual peak demand for determining the planning margin — for example, planning to the average of the eight-hour super-peak period. (New IRP requirement, OPUC Order 06-029, p. 61)	This requirement was met via a Capacity Expansion Module sensitivity analysis. See Chapter 7 for a results summary.
OR	Evaluate, within portfolio modeling, the potential for reducing costs and risks of generation and transmission by including high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas. (New IRP requirement, OPUC Order 06-029, p. 61)	CHP and aggregated dispatchable customer standby generation were modeled as part of a 12% planning reserve margin sensitivity analysis using PaR. See Chapter 7 for a results summary.

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
OR	Evaluate the potential value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment. (New IRP requirement, OPUC Order 06-029, p. 61)	PacifiCorp conducted a study of distribution system investment deferral potential assuming a 5-megawatt CHP interconnection project in the company’s west control area. See Appendix H.
OR	If pumped storage technology becomes a viable resource option in the future, the Commission expects PacifiCorp to analyze the associated environmental costs that ratepayers might incur. (OPUC Order 06-029, p. 53)	Pumped storage was not evaluated in this IRP due to an expected commercial operations date beyond the 10-year acquisition horizon.
OR	Analyze planning margin cost-risk tradeoffs within stochastic modeling of portfolios. If feasible, analyze the cost-risk tradeoff of all portfolios at various planning margins. If not feasible, build all portfolios to a set planning margin, test them stochastically, and adjust top-performing portfolios to higher and lower planning margins for further stochastic evaluation. (New requirement, OPUC Order 06-029, p. 61)	PacifiCorp’s approach to meeting this requirement was to use the CEM to derive optimal portfolios using planning reserve margins set at 12%, 15%, and 18%. To determine the stochastic impacts, these same portfolios were run with the PaR model in stochastic mode. PacifiCorp also simulated risk analysis portfolios derived from CEM runs constrained with both 12% and 15% planning reserve margins.
OR	For the next IRP or Action Plan, analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind’s capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company’s cost to integrate wind resources. (Additional Action Item, OPUC Order 06-029, p. 60)	Proxy wind projects were included as resource options in CEM runs, and included in stochastic simulations for evaluating risk analysis portfolios. See Appendix J for the results of PacifiCorp’s updated studies on wind integration costs, determination of cost-effective wind resources, and wind capacity planning contribution. Appendix J also includes a discussion on the effect of fuel type on wind integration costs. Chapter 7 outlines stochastic simulation results for portfolios with incremental wind additions.
OR	We also expect the Company to fully explore whether delaying a commitment to coal until IGCC technology is further commercialized is a reasonable course of action. (OPUC Order 06-029, p. 51)	PacifiCorp developed and evaluated a portfolio that excludes pulverized coal as a resource option. PacifiCorp also evaluated two additional portfolios that were specified by OPUC staff. These two portfolios, each developed according to 12% and 15% planning reserve

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
		margins respectively, (1) defer pulverized coal until after 2014, (2), include an IGCC plant in 2014, and (3) include 600 MW of additional wind. The portfolio evaluation results are summarized in Chapter 7.
UT	We direct the Company to structure the public input process to allow sufficient time for discussion of issues raised by parties and to address relevant issues raised in this IRP. (Utah PSC, Docket No. 05-2035-01, p. 21)	PacifiCorp organized the public meeting schedule to front-load discussions on key modeling approaches and issues (DSM, renewables, CO ₂ analysis, etc.). The company also distributed papers on scenario analysis and risk analysis portfolio development to provide interim information prior to public meetings. See Chapter 2, “Stakeholder Engagement”.
UT	We believe a comprehensive annual update to the IRP between the biennial IRP filings should continue. (Utah PSC, Docket No. 05-2035-01, p. 21)	PacifiCorp will continue with biennial IRP updates, since this is now a requirement under the new Oregon PUC.
UT	We find reasonable the Division’s request for semi-annual updates of the load and resource balance. (Utah PSC, Docket No. 05-2035-01, p. 21)	PacifiCorp provided a semi-annual update of its load and resource balance at the April 20, 2007 IRP public meeting.
UT	We direct the Company to investigate improving the transparency of the IRP modeling to increase confidence in the results. (Utah PSC, Docket No. 05-2035-01, p. 21)	PacifiCorp provided stakeholders with a detailed modeling plan and scenario/risk analysis methodology, and solicited comments on them prior to the start of IRP modeling. Model results documentation has been distributed at the conclusion of the key portfolio analysis milestones—evaluation of CEM runs, selection of risk analysis portfolios for stochastic simulation, and selection of the preferred portfolio.
UT	Include a section that specifically addresses the PURPA Fuel Sources Standard in all future Integrated Resource Plans. (“Determination Concerning The PURPA Fuel Sources Standard”, Docket No. 06-999-03)	A section on fuel source diversity is included in Chapter 8, “Action Plan”.
UT	Per agreement with Utah Commission staff, include a 20-year forecasted average heat rate trend for the company’s fossil fuel generator fleet that includes IRP resources and currently planned retirements.	A section titled, “Forecasted Heat Rate Trend,” is included in Chapter 7.

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
WA	The recommended reserve margin is greatly influenced by the nature, mix, and capacity of available resources, and risks associated with any particular resource. Thus, the company should quantify the reserve margin in a way that incorporates risks posed by each specific resource. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 10)	PacifiCorp outlined at IRP public meetings (January 13 and May 10, 2006) an innovative statistical approach for determining the amount of an additional resource needed to keep a utility system's Loss of Load Probability (LOLP) constant. This method, which accounts for resource-specific reliability characteristics, was applied in this IRP to determine the Peak Load Carrying Capability for wind resources. PacifiCorp is evaluating this approach for applicability to all resource additions modeled in the IRP.
WA	The Commission expects PacifiCorp's next plan to further refine wind energy's reserve value and effects on the stability of power systems. PacifiCorp should also work to minimize any qualifications around its estimates of the value of wind. The Commission encourages PacifiCorp to continue to explore renewable resources, and to develop these resources when economic and compatible with system objectives. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 7)	See Appendix J for the results of PacifiCorp's updated studies on wind integration costs, determination of cost-effective wind resources, and wind capacity planning contribution. Chapter 7 outlines stochastic simulation results for risk analysis portfolios with different amounts and timing of wind resources. PacifiCorp's preferred portfolio includes 2,000 megawatts of renewables, as opposed to 1,400 megawatts for the original MEHC renewables commitment.
WA	We encourage PacifiCorp to further refine its approach by developing load curves for its west-side control area. The company should explicitly look at the load shapes for residential heating and lighting to assess the potential for DSM and energy efficiency measures in Washington. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 7)	PacifiCorp evaluated its load shapes for Class 2 DSM decrement calculation, and determined that residential lighting load shapes for the west and east control areas should be added. These load shapes are reported in Chapter 5. Decrement results for the new load shapes are reported in Chapter 7, "Class 2 DSM Decrement Analysis".
WA	In the Commission's letter regarding PacifiCorp's 2002 IRP, the company needs to explore ways to quantify the risk preferences of customers and shareholders. Only by understanding its risks and the risk preferences of stakeholders can PacifiCorp rank and prioritize alternative resource portfolios. (WUTC IRP Acknowledgment	PacifiCorp has relied on the public process (including the 2004 IRP stakeholder satisfaction survey conducted in 2005) to solicit customer and other stakeholder views on what risk factors to consider and how to address them in resource portfolio evaluation. PacifiCorp's uncertainty and risk analysis framework for the 2007 IRP reflects this input. For example, the company used risk metrics and

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
	Letter, Docket UE-050095, p. 7)	risk trade-off analysis to address such criteria as overall portfolio cost, supply reliability, and rate volatility impact, among others.
WA	The company should consider the costs and advantages of implementing a multi-objective function optimization [model] as part of its next plan. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 8)	PacifiCorp and WUTC staff participated in a conference call on April 18, 2006, pertaining to this issue and others identified in the WUTC IRP acknowledgment letter. PacifiCorp indicated that it was not aware of a commercially available multi-objective optimization modeling tool suitable for integrated resource planning.
WA	The company needs to develop avoided costs for general purpose energy and capacity in both the short and long-term. Furthermore, PacifiCorp should derive an avoided cost schedule for transmission and distribution resources. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 8)	PacifiCorp makes avoided cost filings after each IRP is filed. The company will consider expanding its avoided cost schedules to cover the areas identified by the WUTC.
WA	PacifiCorp’s plan does not directly consider the price influence of various energy commodities upon on another. PacifiCorp should consider whether its plan would benefit from linking gas, coal and oil prices through a high-level market fundamentals tool. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 8)	PacifiCorp and WUTC staff participated in a conference call on April 18, 2006, pertaining to this issue and others identified in the WUTC IRP acknowledgment letter. The company stated that its fundamentals modeling tool, MIDAS, addresses energy commodity interactions. This topic is addressed in Appendix A in the discussion on commodity prices.
WA	The Commission encourages PacifiCorp to investigate using the most up-to-date models and tools, including, for example, those commonly used by other utilities such as the AURORA production cost and dispatch model. Also, additional detail regarding the algorithms and mathematics of the modeling tools would improve the value of the report. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 4)	PacifiCorp routinely evaluates other computer models for applicability to the IRP process, including AURORA and its competitor products. PacifiCorp conducted an IRP benchmarking study in 2005 in which electric utility use of computer models was investigated. This study was included as Appendix C of the 2004 IRP Update. Regarding the recommendation to disclose additional details on model algorithms and mathematics in the IRP, the company notes that its modeling tools are covered under vendor license agreements that prohibit distribution of proprietary material except when required under regulatory commission order.

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
WA	<p>The Company used the MIDAS model to compute variations off the base forecast. The plan did not document the assumptions, model structure or reliability of PIRA or MIDAS forecasts. PacifiCorp needs to allow access to the models used to forecast prices to Commission staff. Without knowledge of how the models operate staff cannot evaluate the fundamentals forecast model used by PIRA or other agencies. The Commission notes that other utilities in our jurisdiction provide staff access to representatives of the gas supply and price consultants to discuss the mechanics of studies, data source, and policy assumptions used in forecast models. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 5)</p>	<p>PacifiCorp proposes to institute a series of technical workshops on fundamentals modeling for the next IRP, similar to the load forecasting workshops held for the 2004 and 2007 IRPs. PacifiCorp will work with Commission staff to provide knowledge of PacifiCorp's models and associated data and access to the company's consultants and studies upon request and under appropriate confidentiality conditions where necessary.</p>
WA	<p>Increasingly volatile natural gas prices have made short-term price predictions based on fundamentals modeling less reliable. Therefore, price forecasts generated from non-fundamental models and the forwards market should support or supplement the price forecasts used in the two-year actions plan. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 5)</p>	<p>PacifiCorp and WUTC staff participated in a conference call on April 18, 2006, pertaining to this issue and others identified in the WUTC IRP acknowledgment letter. PacifiCorp noted that it uses market information for the first six years of forward gas prices.</p>
WA	<p>Given the importance of individual state policies in PacifiCorp's resource acquisition decisions, the Commission specifically requests that the Company model and evaluate the effects of state specific policies on its decisions to acquire certain resources. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 10)</p>	<p>PacifiCorp and WUTC staff participated in a conference call on April 18, 2006, pertaining to this issue and others identified in the WUTC IRP acknowledgment letter. The Commission's concern was focused on state economic development policies in other states. PacifiCorp agreed to address this issue in narrative fashion given that state economic development initiatives would impact the load forecast and not resource modeling directly. See the load forecasting section entitled, "Treatment of State Economic Development Policies" in Appendix A.</p>

Table I.3 – Oregon Public Utility Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
Guideline 1. Substantive Requirements		
1.a.1	<p>All resources must be evaluated on a consistent and comparable basis: All known resources for meeting the utility’s load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.</p>	<p>PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, and transmission. Chapters 5 and 6 document how PacifiCorp developed and assessed these technologies. In brief, the company used a combination of PacifiCorp generation staff expertise, Electric Power Research Institute Technical Assessment Guide (TAG®) data, and capacity expansion optimization modeling to assess these technologies. Generation resource types were initially assessed by PacifiCorp’s generation experts, and a list that captures the salient technology types and configurations was assembled (Chapter 5, Tables 5.1 and 5.2). Decisions on what generation resources to include in the Capacity Expansion Module was based on generation staff recommendations and the need to limit resource options to a manageable number based on model constraints and run-time considerations. (The company notes that the need to place restrictions on the number of resource options is a common IRP problem for utilities that use such optimization models for long-term planning.)</p> <p>Based on the modeling lessons learned for this IRP and the anticipated expansion of resource options arising from the DSM potentials study due in June 2007, PacifiCorp intends to explore new resource screening methods to accommodate a broader range of technologies while meeting the requirement to assess technologies on a ‘consistent and comparable basis.’”</p>
1.a.2	<p>All resources must be evaluated on a consistent and comparable basis: Utilities should compare different resource</p>	<p>PacifiCorp considered various combinations of fuel types, technologies, lead times, in-service dates, durations, and locations for</p>

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
	fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	both capacity expansion optimization modeling (deterministic risk modeling via scenario analysis) as well as stochastic risk modeling. Chapters 6 and 7 document the modeling methodology and results, respectively. Chapter 5 describes resource attributes in detail. The range of resource attributes accounted for in stochastic risk analysis is indicated in Chapter 7, Tables 7.17 and 7.31 through 7.35. These tables list the resources included in the risk analysis portfolios.
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company used the Electric Power Research Institute’s Technical Assessment Guide (TAG®) to develop generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used Quantec LLC’s proxy supply curves, which applied a consistent methodology for determining technical, market, and achievable DSM potential. All portfolio resources were evaluated using the same sets of inputs. These inputs are documented in Appendix A.
1.a.4	All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PacifiCorp applied its after-tax WACC of 7.1 percent to discount all cost streams.
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	PacifiCorp fully complies with this requirement. Each of the sources of risk identified in this guideline is treated as a stochastic variable in Monte Carlo production cost simulation. See the stochastic modeling methodology section in Chapter 7.
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	PacifiCorp evaluated additional risks and uncertainties, including resource capital costs, coal prices, and the level of DSM achievable potential. See Chapter 6 for a discussion on what variables were modeled for scenario and stochastic risk analysis.

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers (“best cost/risk portfolio”).	PacifiCorp evaluated cost/risk tradeoffs for each of the risk analysis portfolios considered. See Chapter 7 for the company’s portfolio risk analysis and determination of the preferred portfolio.
1.c.1	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PacifiCorp used a 20-year study period for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	PacifiCorp fully complies. Chapter 6 provides a description of the PVRR methodology.
1.c.3.1	To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	PacifiCorp uses the standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates several measures, including stochastic upper-tail PVRR (mean of highest five Monte Carlo iterations), risk exposure (upper-tail mean PVRR minus overall mean PVRR), and 95 th percentile stochastic PVRR.
1.c.3.2	To address risk, the plan should include, at a minimum: 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	A discussion on costs and risks of physical and financial hedging is provided in Chapter 5.
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 7 summarizes the results of PacifiCorp’s cost/risk tradeoff analysis, and describes what criteria the company used to determine what resource combinations provide an appropriate balance between cost and risk.

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and expected state and federal energy policies in portfolio modeling. Chapter 7 describes the decision process used to derive portfolios, which includes consideration of state resource policy directions.
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	PacifiCorp fully complies with this requirement. Chapter 2 provides an overview of the public process, while Appendix F documents the details on public meetings held for the 2007 IRP.
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	Both IRP volumes provide non-confidential information the company used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email.
2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PacifiCorp distributed a draft IRP document for external review on April 20, 2007.
Guideline 3: Plan Filing, Review, and Updates		
3.a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	This Plan complies with this requirement.
3.b	The utility must present the results of its filed plan to the Commission at a public	PacifiCorp will adhere to this guideline.

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
	meeting prior to the deadline for written public comment.	
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	Not applicable
3.d	The Commission will consider comments and recommendations on a utility’s plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	Not applicable
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable
3.f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	Not applicable
3.g	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: <ol style="list-style-type: none"> 1. Describes what actions the utility has taken to implement the plan; 2. Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and 3. Justifies any deviations from the ac- 	Not applicable

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
	knowledge action plan.	
Guideline 4. Plan Components (at a minimum, must include...)		
4.a	An explanation of how the utility met each of the substantive and procedural requirements	The purpose of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions	PacifiCorp developed low, medium, and high load growth forecasts for scenario analysis using the Capacity Expansion Module. Stochastic variability of loads was also captured in the risk analysis. See Chapter 6 for a description of the load forecast data and Chapter 7 for scenario and risk analysis results.
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested	This Plan complies with the requirement. See Chapter 4 for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies, as mentioned in Appendix A (Transmission System).
4.d	For gas utilities only	Not applicable
4.e	Identification and estimated costs of all supply-side and demand side resource options, taking into account anticipated advances in technology	Chapter 5 identifies the resources included in this IRP, and provides their detailed cost and performance attributes (see Tables 5.1 through 5.4).
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs	In addition to incorporating a planning reserve margin for all portfolios evaluated, the company used several measures to evaluate relative portfolio supply reliability. These are described in Chapter 6. PacifiCorp conducted several sensitivity studies to determine the cost/risk tradeoff of different planning reserve margin levels. These studies, and resulting company conclusions, are documented in Chapter 7.
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered	Appendix A and Chapter 6 describe the key assumptions and alternative scenarios used in this IRP.

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
4.h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system	This Plan documents the development and results for 56 portfolios evaluated in this IRP (Chapter 7).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties	Chapter 7 presents the deterministic and stochastic portfolio modeling results, and describes portfolio attributes that explain relative differences in cost and risk performance.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter 7 provides tables and charts with performance measure results, including rank ordering as appropriate.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	PacifiCorp fully complies with this guideline. See the responses to 1.b.1 and 1.b.2 above.
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is presumed to have no inconsistencies.
	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapter 8 presents the 2007 IRP Action Plan.
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and	PacifiCorp evaluated proxy transmission resources on a comparable basis with respect to other proxy resources in this IRP. For example, the Capacity Expansion Module was allowed to select the most economic transmission options given other supply and demand-side resource options selected by the model. Fuel transportation costs were

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
	sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	factored into resource costs.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	A multi-state demand-side management potentials study is scheduled for completion in June 2007.
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	A discussion on the treatment of conservation programs (Class 2 DSM) is included in Chapter 6, “Oregon Public Utility Commission Guidelines for Conservation Program Analysis in the IRP.”
6.c	To the extent that an outside party administers conservation programs in a utility’s service territory at a level of funding that is beyond the utility’s control, the utility should: <ol style="list-style-type: none"> 1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and 2. Identify the preferred portfolio and action plan consistent with the outside party’s projection of conservation acquisition. 	See the response for 6.b above.
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PacifiCorp evaluated demand response resources (Class 3 DSM) on a consistent basis with other resources in its CEM alternative future scenario analysis, as well as conducted a sensitivity analysis using the Planning and Risk Module. See Chapter 7.
Guideline 8: Environmental Costs		
8	Utilities should include in their base-case analyses the regulatory compliance costs they expect for carbon dioxide (CO ₂), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO ₂ regulatory costs in	This IRP fully complies with the CO ₂ compliance cost analysis requirements in Order No. 93-695. Modeling results for the CO ₂ cost adder levels are reported in Chapter 7.

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
	Order No. 93-695, from zero to \$40 (1990\$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.	
Guideline 9: Direct Access Loads		
9	An electric utility’s load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	PacifiCorp continues to plan for load for direct access customers.
Guideline 10: Multi-state Utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2007 IRP conforms to the multi-state planning approach as stated in Chapter 2.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility’s chosen portfolio achieves its stated reliability, cost and risk objectives.	PacifiCorp fully complies with this guideline. See the response to 1.c.3.1 above. Chapter 8 describes the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO ₂ cost adder levels were used to inform the cost/risk tradeoff analysis. The preferred portfolio was also shown to meet reliability goals on the basis of average annual Energy Not Served and other reliability measures (Chapter 7).
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp evaluated several types of distributed generation, including combined heat and power and customer-owned standby generation. The results of these evaluations are documented in Chapter 8.
Guideline 13: Resource Acquisition		

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
13.a	An electric utility should, in its IRP: <ol style="list-style-type: none"> 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party 3. Identify any Benchmark Resources it plans to consider in competitive bidding 	Chapter 8 outlines the procurement approach for each proxy resource type identified in the action plan. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 8. Benchmark resources for the 2012 are cited in Chapter 3, Recent Resource Procurement Activities.
13.b	For gas utilities only	Not applicable

Table I.4 – Utah Public Service Commission IRP Standard and Guidelines

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Utah Public Service Commission responsibility
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the IRP process.
3	Prudence Reviews of new resource acquisitions will occur during ratemaking proceedings.	Not addressed; ratemaking occurs outside of the IRP process
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.	PacifiCorp’s public process is described in Chapter 2. A record of public meetings is provided as Appendix F.
5	Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analy-	PacifiCorp used a scenario analysis approach along with externality cost adders to model environmental externality costs. See Chapter

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
	sis.	6 for a description of the methodology employed.
6	The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.	Supply, transmission, and demand-side resources were evaluated on a comparable basis using PacifiCorp’s capacity expansion optimization model (CEM). (The one exception was Class 2 DSM, due to the unavailability of supply curves for this IRP.) Also see the response to number 4.b.ii below.
7	Avoided Cost should be determined in a manner consistent with the Company's Integrated Resource Plan.	Consistent with the Utah rules, PacifiCorp determination of avoided costs will be handled in a manner consistent with the IRP, with the caveat that the costs may be updated if better information becomes available.
8	The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.	This IRP was developed in consultation with parties from all state jurisdictions, and meets all formal state IRP guidelines.
9	The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	PacifiCorp’s business plan is directly related to the IRP; the business planning process is informed by the IRP resource analysis, the action plan, and subsequent procurement activities. Due to timing and scope differences, these two plans do not match in all respects. The 2007 IRP will be used to inform the next version of the Business Plan.
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk	Chapter 2 discusses the planning principles used for developing this IRP, and the qualifications surrounding the company’s long term resource planning process. The company notes that this definition does not specify what constitutes “optimality” given resource decision-making constrained by (1) consideration of risk, uncertainty, disparate state policy goals and stakeholder interests, and (2) the complexity and limitations of the IRP modeling effort. As indicated in Chapter

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
	and uncertainty.	2, PacifiCorp believes that a successful IRP attempts to derive a robust resource plan under a reasonably wide range of potential futures
2	The Company will submit its Integrated Resource Plan biennially.	For this IRP, the company received a filing extension from the Utah Public Service Commission and other state commissions. This extension was necessary to realign the IRP process to address new and expected changes in state resource policy that came into play well into this IRP development cycle.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	PacifiCorp’s public process is described in Chapter 2. A record of public meetings is provided as Appendix F.
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.	PacifiCorp implemented a load forecast range for both deterministic scenario analysis as well as for stochastic short-term and long-term variability. Details concerning the load forecasts used in the 2007 IRP are provided in Chapter 4 and Appendix A. Details on the forecast ranges developed for scenario and stochastic analysis are documented in Chapter 6 and Appendix E, respectively.
4.a.i	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	<p>Price risk associated with market sales is captured in the company’s stochastic simulation results. Current off-system sales agreements are included in the IRP models.</p> <p>The company is not planning to enter into additional long term firm sales agreements; therefore, associated risks do not impact the selection of the preferred portfolio. For system balancing sales, PacifiCorp recognizes that transactions may be affected by new resource constraints imposed by regulators (carbon emission and renewable portfolio standards in particular). These impacts will</p>

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
		be considered in future IRP resource analyses.
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Appendix A documents how demographic and price factors are used in the load forecasting process. Appendix A also documents price elasticity studies conducted on Utah load.
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the Capacity Expansion Module. There were some exceptions due to the availability of data for this IRP, such as Class 2 DSM. Chapter 6 provides a discussion on how Class 2 DSM resource potential was addressed in this IRP.
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	<p>PacifiCorp contracted with Quantec, LLC to assess the technical, market, and achievable potential for various dispatchable and price-responsive load control programs (PacifiCorp Class1 and Class 3 DSM). The associated assessment is described in Chapter 5, while Quantec’s assessment report is included as Appendix B.</p> <p>PacifiCorp’s treatment of conservation programs (Class 2 DSM) is addressed in Chapter 6 (“Public Utility Commission Guidelines for Conservation Program Analysis in the IRP”).</p>
4.b.ii	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, and transmission. Chapters 5 and 6 document how PacifiCorp developed and assessed these technologies. In brief, the company used a combination of PacifiCorp generation staff expertise, Electric Power Research Institute Technical Assessment Guide (TAG®) data, and capacity expansion optimization modeling to assess these technologies. Generation resource types were initially assessed by PacifiCorp’s

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
		<p>generation experts, and a list that captures the salient technology types and configurations was assembled (Chapter 5, Tables 5.1 and 5.2). Decisions on what generation resources to include in the Capacity Expansion Module was based on generation staff recommendations and the need to limit resource options to a manageable number based on model constraints and run-time considerations. (The company notes that the need to place restrictions on the number of resource options is a common IRP problem for utilities that use such optimization models for long-term planning.)</p> <p>Based on the modeling lessons learned for this IRP and the anticipated expansion of resource options arising from the DSM potentials study due in June 2007, PacifiCorp intends to explore new resource screening methods to accommodate a broader range of technologies while meeting the requirement to assess technologies on a ‘consistent and comparable basis.’”</p>
4.b.iii	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.	PacifiCorp captures and models these resource attributes in its IRP models. The proxy demand curves used to represent demand-side management programs explicitly incorporates estimated rates of program and event participation.
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	A description of the role of competitive bidding and other procurement methods is provided in Chapter 8 (“IRP Resource Procurement Strategy”).
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2007-2026)
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe spe-	The action plan is provided in Chapter 8. A status report of the actions outlined in the previous action plan (2004 IRP and the 2004 IRP Update) is provided as Appendix G.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
	<p>cific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.</p>	
4.f	<p>A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.</p>	<p>Chapter 8 includes a section that describes PacifiCorp’s strategy for meeting this requirement. In short, the company will use its IRP models, in conjunction with scenario analysis, to evaluate resource bids submitted under its Base Load Request For Proposals, issued on April 5, 2007.</p>
4.g	<p>An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.</p>	<p>PacifiCorp provides resource-specific utility and total resource cost information in Chapter 5 (Tables 5.2 through 5.4).</p> <p>The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways:</p> <ul style="list-style-type: none"> ● Portfolios were evaluated using CO₂ adders that ranged from \$0 to \$61 per ton. ● The cost impact of renewable portfolio standards is captured in several portfolio scenario analyses (Chapter 7) ● PacifiCorp conducted a study to determine the cost and risk impact of widespread adoption of a greenhouse gas emissions performance standard (Chapter 7) ● Appendix B includes a section on DSM program valuation, which covers societal value factors (for example, environmental and reliability benefits)
4.h	<p>An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should</p>	<p>Discussions on market risks by resource type are included in Chapter 5 (“Resource Descriptions”).</p> <p>Resource capital cost uncertainty and technological risk is addressed in Chapter 5 (“Handling of Technology Improvement</p>

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
	bear such risk, the ratepayer or the stockholder.	Trends and Cost Uncertainty”). For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Chapter 2.
4.i	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	PacifiCorp discusses how planning flexibility came into play for the selection of the preferred portfolio (Chapter 7, “Preferred Portfolio Selection and Justification”).
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	PacifiCorp examined the trade-off between portfolio cost and risk. This trade-off analysis is documented in Chapter 7. A discussion on the trade-off between cost and the planning reserve margin is also provided in Chapter 7 (“Planning Reserve Margin Selection”).
4.k	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.	PacifiCorp estimated environmental externality costs for CO ₂ , NO _x , SO ₂ , and mercury with use of cost adders and assumptions regarding the form of compliance strategy (for example, cap-and-trade versus a per-ton tax for CO ₂). For CO ₂ externality costs, the company used scenarios with various cost adder levels to capture a reasonable range of cost impacts.
4.l	A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.	This narrative is provided in Chapter 4 (“Existing DSM Program Status”).
5	PacifiCorp will submit its IRP for public comment, review and acknowledgement.	PacifiCorp distributed the draft IRP document for public review and comment on April 20, 2007. This IRP report constitutes

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
		the formal submission of the IRP for acknowledgement.
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required.	Not addressed; this is a post-filing activity.
7	Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

APPENDIX J – WIND RESOURCE METHODOLOGY

This appendix summarizes the wind resource analyses used to help characterize wind resources included in PacifiCorp’s IRP models. Specifically, the appendix covers (1) the expected cost of integrating various amounts of wind generation with other portfolio resources—reflecting a refinement and update of previous analysis conducted for PacifiCorp’s integrated resource planning, (2) a resource screening effort to determine a base amount of wind resources to include in portfolios subjected to stochastic production cost simulation, and (3) the calculation of capacity planning contribution of wind resources, accounting for generation variability.

In addition to summarizing the results of its wind resource studies, this appendix briefly describes current efforts by organizations in the Pacific Northwest to assess wind integration implications. Finally, the last section of this appendix discusses the role of resource fuel type on the company’s strategy for integrating wind resources. This discussion addresses an Oregon Public Utility Commission requirement to investigate this topic for the 2007 IRP.

A new methodology was developed to explicitly calculate the load following reserve requirement based on the uncertainty in load for the next hour on an operational basis, which allowed PacifiCorp to apply the same analytical approach to estimating the incremental reserve requirements for wind. The availability of hourly wind data for resources distributed across PacifiCorp service territories over comparable historical time horizons enabled analysts to include proxy wind resources with realistic operating characteristics into the analysis. Further, a development in techniques for estimating load carrying capability allowed analysts to estimate the capacity contributions of various wind combinations of wind developments that restricted interactions due to correlated generation from nearby plants. Analysts were able to improve the characterization of wind operations and interactions with the power system in the present analysis.

WIND INTEGRATION COSTS

Across all analyses, wind integration costs have generally been divided into two categories – incremental reserve requirements and system balancing costs. The former is related to the need for dynamic resources to be held in reserve, able to respond on a roughly ten minute basis to rapidly changing load/resource balance conditions. Since wind resource generation can be quite variable over time periods from about ten minutes to several hours, it will be necessary to increase the amount of reserves as the quantity of wind resources on the system increases. System balancing costs represent the difference in value between the energy delivered from wind resources compared to that delivered from less volatile resources. Consistent with previous studies, PacifiCorp reviewed both categories of wind integration costs: the incremental reserve requirement and the system balancing cost.

Incremental Reserve Requirements

Operating reserves are divided into categories based on purpose and on characteristics. Naming conventions for categorizing reserves by their intended purpose are not standard in the industry. Reserves held for responding to the sudden failure of generation or transmission equipment are usually called “contingency reserves”. Reserves held to respond to changes in system frequency

over a period of a few seconds will be referred to as “regulating reserves”. Generation that can be brought on over a multiple-minute time period will be termed “load following reserves.”

Wind projects are not expected to affect the need to hold contingency reserves, as there is no significant difference between wind generation and other types of generation with respect to sudden equipment failures, or other outages. The multiplicity of individual generators within a typical wind farm inherently makes them less susceptible to losing the entire output of the farm due to generator or turbine failures (but not transmission-related outages). Wind projects are subject to relatively rapid shutdown when wind speeds reach the cutout level. However, this has not been a significant problem in practice, as individual wind turbines do not tend to shut down simultaneously.

Similarly, regulating reserve requirements do not appear to be significantly affected by wind turbines⁴. The second-by-second variations in wind project output are found to be not significantly different from other generating units and the ambient fluctuations of the load. They are also not correlated with either load fluctuations, or distant wind projects.

Wind variations over periods of ten minutes to an hour are significant, and can cause operators to rapidly start up units on short notice within an hour. Fluctuations of the combined output of a collection of wind projects increases with the amount of total wind generation connected to the system.

For the 2007 IRP, a new methodology was developed to explicitly calculate the load following reserve requirement based on the uncertainty in load for the next hour on an operational basis. Operators have estimates of the behavior of loads for the next hour and move to bring on or back off resources as necessary to accommodate the expected change. Knowing that the actual load of the next hour will likely be different than the forecast and that there will be deviations within the hour, operators hold additional resources ready to respond should they underestimate the need for resources. (Generally, overestimates are not a problem, though it is an additional concern). Reserve levels are established to ensure that the shortfall can be met a minimum percentage of the time—generally around 95 percent. The methodology is graphically illustrated in Figure J.1, which shows how the load forecast changes from one hour to the next. Assuming that the range of actual outcomes for the next hour can be approximated by a normal distribution, the amount of additional reserve capability that is necessary to provide assurance of having adequate resources available at least 95 percent of the time can be calculated.

This methodology can be applied first to the system load alone and then again to the system load net of wind generation. The difference between the two results is the estimated incremental reserve requirement due to the wind resources.

⁴ DeMeo, Grant, Milligan, and Schuenger, “Wind Plant Integration: Costs, Status, and Issues”, IEEE Power & Energy Magazine, Vol 3 Number 6, Nov/Dec 2005, p. 41.

Figure J.1 – Load Following Reserve Requirement Illustration

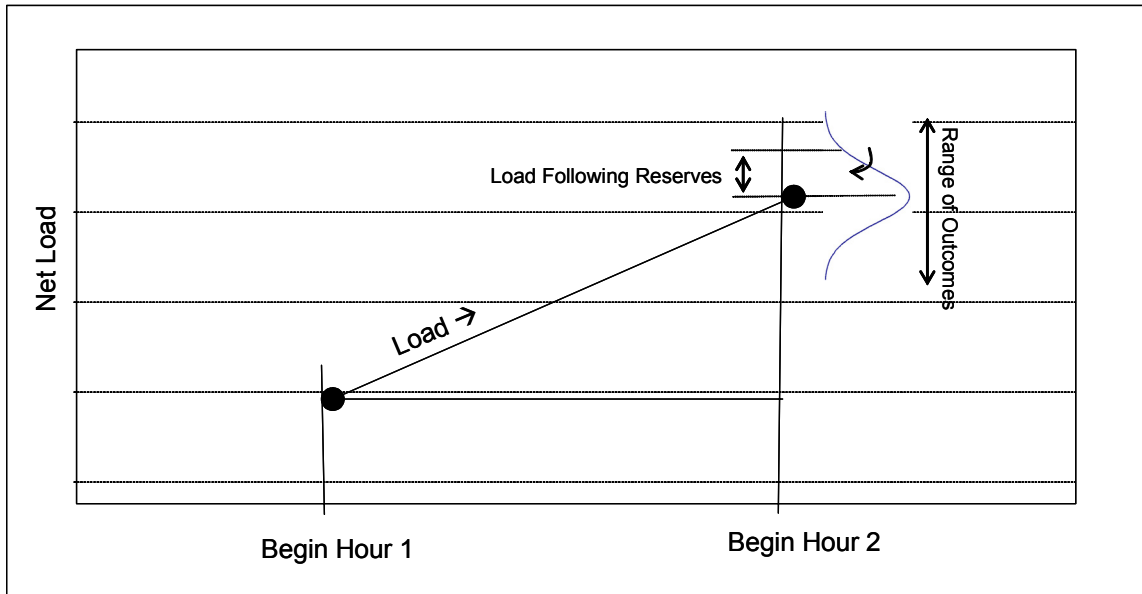
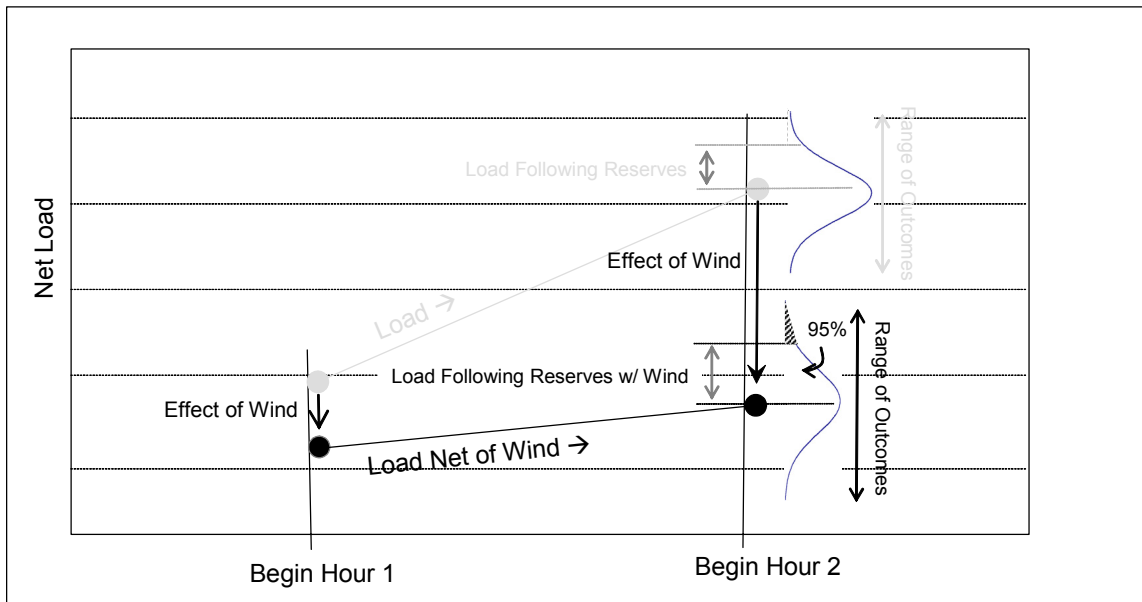


Figure J.2 shows the variability of the load forecast and the variability of the wind energy rolled together by performing the same analysis on the forecast of load net of wind energy. The expected value of load net of wind will be less than or equal to the load forecast for any given hour. However, the variability of load net of wind is greater than that of load alone. It is the difference of between the variability of load and the variability of load net of wind for a given hour that described the incremental reserves that should be attributed to wind resources.

Figure J.2 – Load Following Reserve Requirement for Load Net of Wind

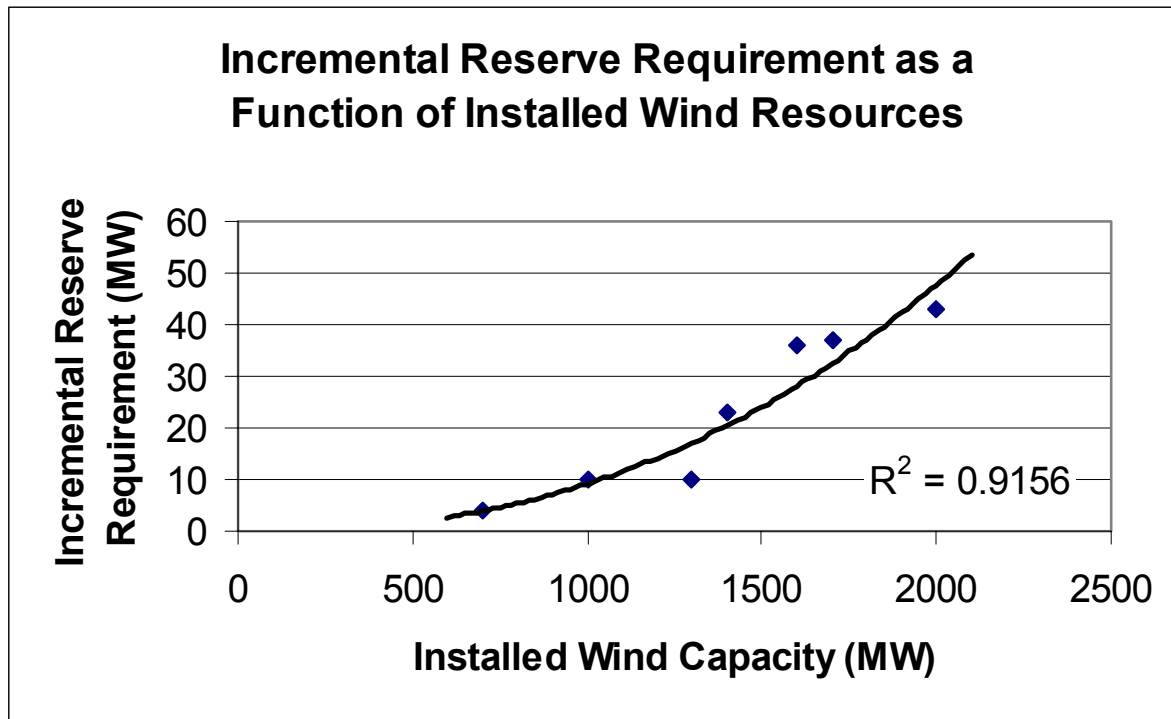


Early in the 2007 IRP process, the result of applying this methodology to the PacifiCorp system with an additional 1,400 megawatts of wind resources was an estimated 30 megawatts of additional reserve requirements. That amount of spinning reserve was added to the stochastic PaR model runs to simulate the additional cost.

In follow up analyses of the preferred portfolio, the company confirmed that using even the simplest forecast techniques greatly reduced the forecast error of both load and wind and consequently reduced the anticipated need for load following reserves. Figure J.3 displays the estimated incremental load following requirement calculated using PacifiCorp’s updated load forecast and varying the level of wind resources following the build pattern of the preferred portfolio. For the 1,400 megawatt level of wind installation, the estimated need for incremental reserves is approximately 22 megawatts. For the preferred portfolio with 2,000 megawatts of wind resources, Figure J.4 shows an estimated need for 43 megawatts of additional load following reserves due to wind resources.

This analysis represents a reduction in the estimate of needed reserves compared with previous estimates. The major difference from prior studies is the development of a systematic method for estimating load following reserve requirements. The 2003 IRP study was based on the hourly variability of wind resources, whereas the current analysis is based on the hourly uncertainty in generation. It is further benefited by the more extensive operating data available since the 2003 study.

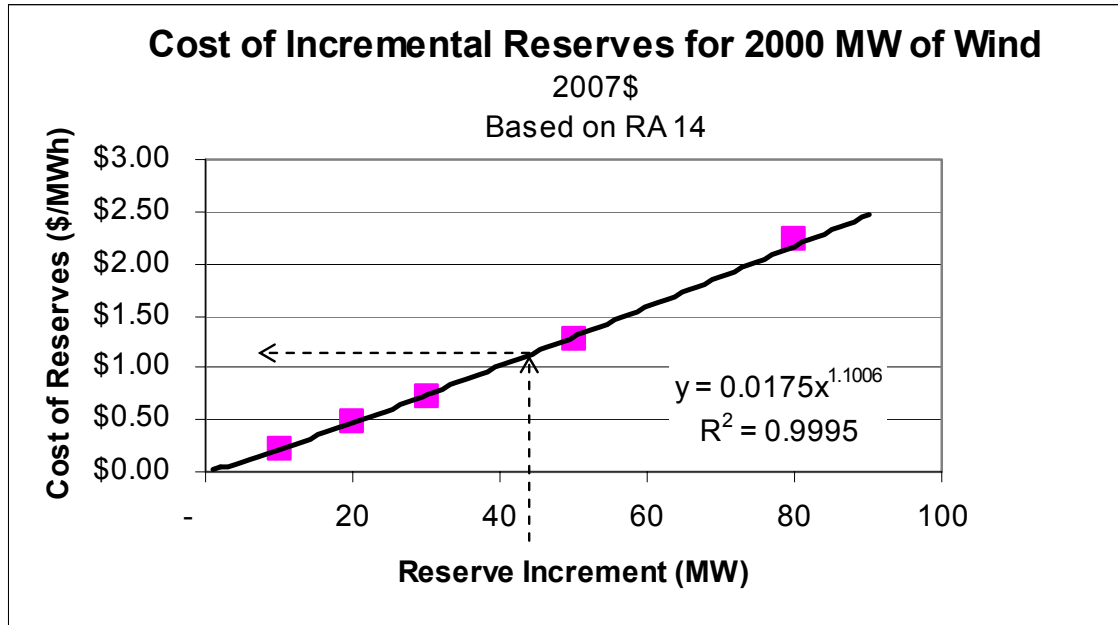
Figure J.3 – Incremental Reserve Cost Associated with Various Wind Capacity Amounts



By running the PaR model studies with and without the incremental load following reserves, the company can estimate the cost of the incremental reserves at varying levels. This can be con-

verted to a unit cost by dividing the cost by the total amount of wind energy. Figure J.4 shows the results of those studies.

Figure J.4 – Operating Cost of Incremental Load Following Reserves



From Figure J.4, the unit cost of 43 megawatts of incremental reserves attributed to the 2,000 megawatts of wind capacity in the preferred portfolio is estimated to be \$1.10 per megawatt hour of wind energy.

System Balancing Costs

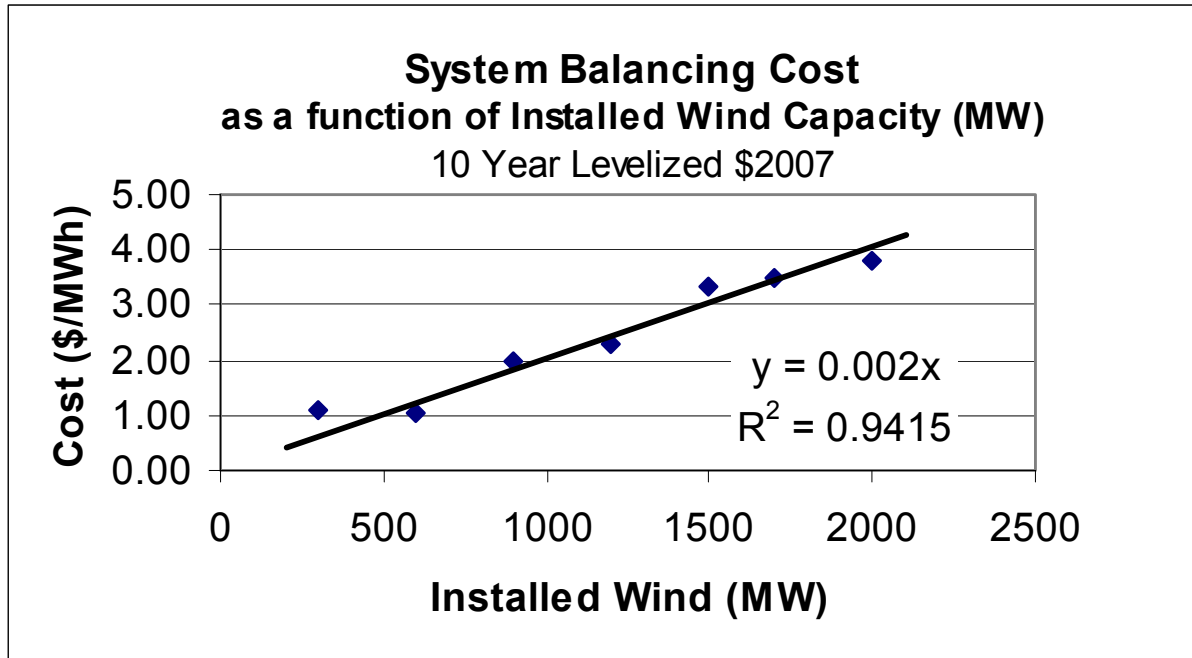
System balancing costs represent the additional operating costs incurred as a result of adding wind generation to PacifiCorp's system. For the 2003 IRP, the system balancing costs associated with wind resources were evaluated by comparing one model run with wind resources specified with an hourly energy pattern to another run where the hourly wind energy was replaced by an equal amount of energy expressed as a flat annual shape. This methodology was repeated for the 2007 IRP preferred portfolio with the following modifications.

- First, the hourly wind patterns for the base study were substantially upgraded. Data from multiple Pacific Northwest sources, including PacifiCorp's actual wind energy, was modified for project size and mapped to the proxy wind resources by location. In the case of multiple "plants," some of the data was shifted by an hour or two to represent diversity within a wind area. The Wyoming projects were updated to a 40 percent capacity factor to be consistent with actual information coming from that area.
- The comparison to the annual block size was repeated for several sized accumulations of wind projects across PacifiCorp's system using the wind data and build patterns consistent with the preferred portfolio analysis.

Using the equivalent annual block against the hourly wind patterns confirmed earlier findings that as wind resources accumulate the system balancing costs also increase on a unit cost basis.

The 2007 IRP results are shown in Figure J.5. The results are similar to previous studies.

Figure J.5 – PacifiCorp System Balancing Cost



From Figure J.5 it can be seen that 2000 megawatts of wind capacity installed on PacifiCorp’s system brings with it approximately \$4.00 per megawatt-hour less than an equivalent amount of energy shaped as an annual base load resource

While some of the regional studies employed smaller sized energy blocks for similar comparisons, PacifiCorp continues to use the annual block-size approach. Equivalent energy generated at a constant rate for the entire year and priced at market is the competing resource that PacifiCorp uses in its resource economic evaluations.

Use of Wind Integration Cost Estimates in the 2007 IRP Portfolio Analysis

Wind integration costs for the purposes of the CEM runs were based on 2004 IRP results due to the timing of the needed analyses. In the PaR model, the system balancing costs are implicit as the wind resources are represented as hourly generation patterns from the quasi-historical data. The incremental load-following reserve requirement, calculated outside of the main IRP models, was added as a constraint in the stochastic PaR runs for the candidate and preferred portfolios in the 2007 IRP. (CEM does not model reserve requirements, and so was not affected by the analysis).

Because the hourly generation patterns of wind and the increased incremental reserves are modeled explicitly in the PaR model the PVRR includes both types of cost. The integration cost for the 2,000 megawatts of wind resources included in the preferred portfolio is estimated to be \$5.10 per megawatt hour of wind energy.

PacifiCorp is continuing to explore methodologies to confirm and quantify wind variability with respect to the need for operating reserves. In particular, sub-hourly data is being captured to test the impact of deviations within the hour. Continued study of the impacts of integrating large quantities of wind in PacifiCorp's system is identified in the IRP action plan (See Chapter 8).

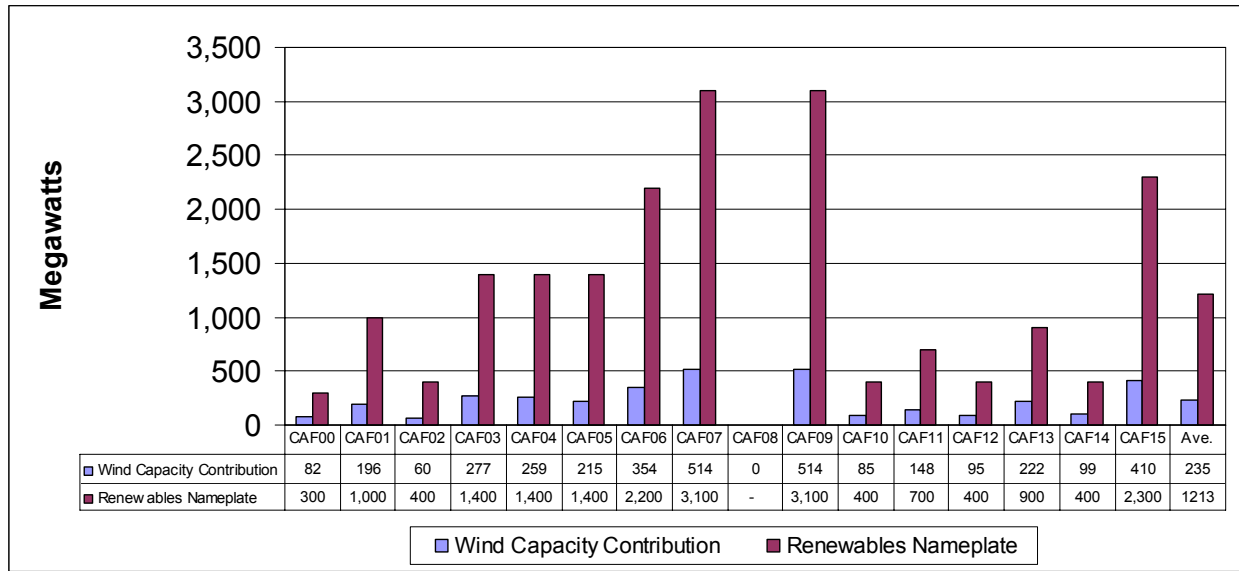
DETERMINATION OF COST-EFFECTIVE WIND RESOURCES

PacifiCorp used the CEM to help determine the quantity of wind considered reasonable given a range of alternative assumptions concerning future portfolio costs. The explicit costs of wind (capital and integration costs, less production tax credits and the value of renewable energy credits) were entered into the CEM. The results of the alternative future scenario CEM runs were examined to find a rough cost-effectiveness order for the proxy wind resource sites. Nearly all of the CEM runs found wind to be part of a cost-effective resource portfolio.

Fixed in each of the runs were the 400 megawatt MEHC acquisition commitments made to state commissions. In the “medium case” alternative future scenario (Alternative Future #11), the CEM added 700 nameplate megawatts of wind resources to the system, for a total of 1,100 megawatts of additional renewable resources by 2016.

Figure J.6 shows the cost-effective wind capacity amounts (both nameplate and capacity contribution) selected by the CEM for each of the 16 alternative future scenarios. The average for all the alternative future runs was over 1,200 megawatts (235 megawatt capacity contribution), or 1,600 megawatts including the 400 megawatt base assumption quantity. These results are consistent with the 1,400 megawatt determination for the level of cost-effective renewables reported in PacifiCorp's 2004 IRP.

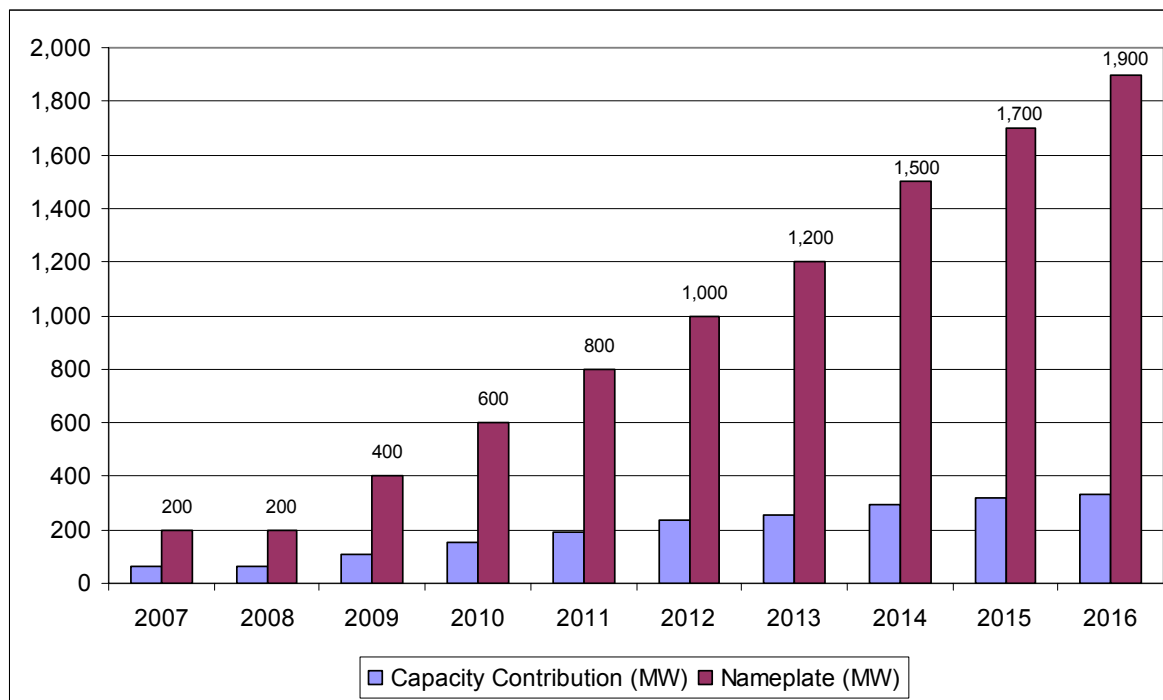
Figure J.6 – Renewables Capacity Additions for Alternative Future Scenarios



A CEM sensitivity run was performed to test the quantity of wind selected given the expiration of renewable production tax credits, but with otherwise favorable scenario conditions for wind development. These favorable conditions included a high CO₂ adder (\$25/ton in 1990 dollars), high natural gas and electricity prices, and a high system-wide renewable sales percentage requirement attributable to renewable portfolio standards. See Chapter 6, Modeling and Risk Analysis Approach, for more details on scenario assumptions.

In this sensitivity, the CEM selected 1,900 megawatts of wind by 2016 (capacity contribution of 335 megawatts). Figure J.7 shows the cumulative annual resource addition pattern for 2008 through 2016. The sensitivity results indicate that given the assumed favorable scenario conditions, the expiration of the production tax credits results in 1,200 megawatts less wind capacity selected for the optimal portfolio.

Based on these results, PacifiCorp identified 1,000 to 1,600 megawatts of additional nameplate wind capacity for specifying proxy renewable resources to be included in portfolios subjected to stochastic production cost simulation.

Figure J.7 – Cumulative Capacity Contribution of Renewable Additions for the PTC Sensitivity Study

WIND CAPACITY PLANNING CONTRIBUTION

For planning purposes, most resources are assumed to contribute their nominal (or “nameplate”) capacity to meeting the planning reserve margin level. It is recognized that wind resources cannot be depended on to contribute their full nameplate capacity to meeting planning reserve margin, since the probability of achieving that level on a peak hour is relatively low, and virtually zero for a large portfolio of diverse wind resources. Nevertheless, it was recognized that some level of capacity contribution attributed to wind projects is appropriate, and PacifiCorp has adopted the effective load carrying capability of wind projects as the standard. In short, the effective load carrying capability of a resource is the amount of incremental load the system can meet with the incremental resource without degrading the reliability of meeting load.

PacifiCorp used the stochastic PaR model to estimate the monthly load carrying capability of a wind resource using an analytical method based on the Z statistic.⁵ The analytical method of estimating load carrying capability was necessary in order to compute the capacity contributions from a large number of wind projects and different combinations of projects. The result of this analysis as applied to the proxy (100-megawatt) wind resources is shown in Table J.1 below. Key observations from these results include the following.

⁵ 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.

- The incremental capacity contribution within an area declines due to correlations (lack of diversity) among wind projects in an area.
- The capacity contribution decline is greatest for projects with more variability of their on-peak contributions.
- The capacity contribution varies over the year, primarily due to expected on-peak generation.

Table J.1 – Incremental Capacity Contributions from Proxy Wind Resources

Regional Resource Additions (MW)		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NC OR	-100	1	18	28	17	25	35	37	27	22	14	5	5
	-200	0	8	16	7	14	24	28	18	12	5	0	0
	-300	0	0	3	0	3	14	19	10	2	0	0	0
	-400	0	0	0	0	0	3	10	1	0	0	0	0
SE WA	-100	19	14	33	13	13	10	12	7	10	14	16	16
	-200	8	2	20	2	1	0	2	0	0	3	5	4
	-300	0	0	8	0	0	0	0	0	0	0	0	0
	-400	0	0	0	0	0	0	0	0	0	0	0	0
EC NV	-100	18	20	32	32	23	28	27	23	21	23	19	28
	-200	15	17	29	26	20	24	23	20	17	20	17	24
	-300	13	14	25	20	16	20	20	18	13	16	14	21
	-400	10	12	21	14	13	17	16	15	9	13	12	17
SE ID	-100	26	37	59	35	31	32	25	32	22	32	38	32
	-200	20	31	53	29	26	27	21	28	17	26	32	26
	-300	14	24	47	24	22	22	17	24	13	21	25	20
	-400	8	17	41	18	17	17	13	20	8	16	18	14
WC UT	-100	13	10	25	31	35	27	20	26	26	24	20	19
	-200	10	9	21	27	31	24	18	22	22	20	17	16
	-300	7	7	17	22	26	20	15	18	18	16	14	13
	-400	4	6	13	17	21	17	12	15	13	13	11	10
SW WY	-100	33	27	36	33	30	30	23	24	25	31	24	34
	-200	27	24	29	27	26	25	20	21	22	26	21	28
	-300	21	20	22	21	21	21	18	18	19	21	18	22
	-400	16	16	15	16	16	16	15	16	16	16	15	16
	-500	10	12	8	10	11	11	13	13	13	11	13	10
	-600	5	8	1	4	6	7	10	10	9	6	10	4
SC MT	-100	0	5	0	0	2	2	7	7	6	1	7	0
	-200	42	34	35	24	26	26	27	26	28	32	42	33
	-300	34	27	26	19	23	21	24	23	24	28	33	26
	-400	26	20	18	14	19	16	21	20	21	23	25	18
SE WY	-100	18	14	10	9	15	11	18	18	18	19	17	11
	-200	35	26	30	25	22	19	13	15	18	23	44	37
	-300	30	21	24	21	18	16	11	13	15	18	43	32
	-400	25	16	19	17	14	12	9	10	11	13	43	27
	-500	20	12	13	13	10	9	7	8	7	9	42	23
	-600	15	7	7	9	6	6	5	6	3	4	41	18
	-700	9	2	2	5	2	3	3	3	0	0	40	13
	4	0	0	1	0	0	1	1	0	0	39	8	

REGIONAL STUDIES

Utilities are studying wind resources in order to quantify the full cost of integrating wind energy into existing systems. In March 2007, Northwest Power and Conservation Council released the Northwest Wind Integration Action Plan (the Action Plan). A joint product of the region’s utility, regulatory, consumer and environmental organizations, the Action Plan addresses several major questions surrounding the growth of wind energy and suggests areas that need further consideration.

The Action Plan summarizes the results of wind integration cost studies performed by PacifiCorp (in its 2004 IRP), Avista, Idaho Power, Puget Sound Energy, and Bonneville Power. The report lists the key findings of these northwest studies. All of the studies find that the cost of integrating wind starts low as the variability of small quantities of wind generation is lost in the volatility of the system load, and grows as the amount of wind resource increases. Collectively the studies list the size of the control area in relation to the amount of wind, the geographic diversity of the wind locations, the amount of flexibility of the receiving utility, and the access to robust markets as key factors affecting the cost of integrating wind energy.

Table J.2 reproduces the data from the report. The Action Plan includes a summary of each of the study methodologies in its appendix B. PacifiCorp’s estimate of wind integration costs ranked among the lowest of the wind integration costs. Only Bonneville Power ranked lower. PacifiCorp’s low integration cost is likely the result of the opportunity to maximize the use of each of the key factors: a large system, wide geographic coverage allowing for dispersed wind sites, and a flexible system with multiple points of access to the energy markets.

Table J.2 – Wind Integration Costs from Northwest Utility Studies ⁶

Utility	Peak Load (MW)	Wind Penetration (\$/MWh of Wind Generation)			
		5%	10%	20%	30%
Avista	2,200	\$ 2.75	\$ 6.99	\$ 6.65	\$ 8.84
Idaho Power	3,100		\$ 9.75	\$11.72	\$16.16
Puget Sound Energy	4,650	\$ 3.73	\$ 4.06		
PacifiCorp (2003-2004 IRP)	9,400	\$ 1.86	\$ 3.19	\$ 5.94	
BPA (within-hour impacts only)	9,090	\$ 1.90	\$ 2.40	\$ 3.70	\$ 4.60

In the wake of the regional load peak of July 24, 2006, when wind turbines made only a small contribution to generating capacity at the time of the peak, the wind resource contribution to peak capacity is being reassessed by Northwest Resource Adequacy Forum (NwRA Forum) as Action #1 of the Action Plan.⁷

⁶ Source: NwRA Forum, Northwest Wind Integration Action Plan, (March 2007 pre-publication version), page 31.

⁷ NwRA Forum, Northwest Wind Integration Action Plan (March 2007, pre-publication version). See Action 1, p.48,

EFFECT OF RESOURCE ADDITION FUEL TYPE ON THE COMPANY'S COST TO INTEGRATE WIND RESOURCES

As the company installs larger volumes of wind resource generation, the cost to integrate these intermittent resources is anticipated to increase. This is because more non-wind resources must be held back to allow flexibility to follow the intra-hour volatility of the wind generation. Resources with greatest the dispatch flexibility that are not already in use to serve load are typically used for integration.

The hour to hour dispatch of non-wind resources is not a trivial decision. The company's owned hydro plants with storage capability and the Mid-Columbia hydro contracts, all of which have the highest flexibility, can often provide the needed flexibility. However, these hydro resources do not have enough volume to integrate all of the anticipated wind variability. Partially loaded gas turbines can provide additional flexibility. Due to its low cost, coal is normally fully utilized to serve load rather than backed off to provide wind integration.

It is flexible resources that are operating on the margin that influence the cost of wind integration. When evaluating the effect of the fuel type of resource additions on PacifiCorp's cost to integrate wind resources, it is most likely that the IRP natural gas-fired additions will have the most effect on integration costs.