1. EXECUTIVE SUMMARY

PacifiCorp's 2003 Integrated Resource Plan (IRP) was filed on January 24, 2003. The IRP process supports PacifiCorp's objective of providing reliable and least cost electric service to all of its customers while minimizing the substantial risks inherent in the electric utility business. The January IRP report described prudent future actions to fulfill this objective, based on the best information known at the time. The IRP was developed with considerable public involvement from customer interest groups, regulatory staff, regulators and other stakeholders. The IRP was submitted to all 6 States that regulate PacifiCorp's retail electric operations and was acknowledged in all States with IRP Standards and Guidelines requiring an acknowledgement process.

PacifiCorp recognizes that integrated resource planning is a continuous process rather than a one-time or occasional event. The plan stated (pg. 152) that the IRP Action Plan "will be implemented as described…but is subject to change as new information becomes available or as circumstances change." Also, the plan stated (pg. 152) that it is "PacifiCorp's intention to revisit and refresh the Action Plan no less frequently than annually." This IRP Update satisfies that commitment.

Since the last IRP was completed, PacifiCorp has continued its long-term planning work and improvements to models, assumptions and processes. Changes to inputs and assumptions include a revised load forecasting methodology resulting in an updated 20 year forecast, changes to coal plant development timelines, and an improved representation of transmission issues in our modeling, and market prices.

PacifiCorp has also conducted further detailed model validation against actual system operations data and has improved the synchronization of short-term operations and planning with long-term IRP planning efforts.

This work has resulted in a revised load-resource balance for PacifiCorp and an enhanced way of representing this balance by location. The improved analysis allows us to understand better the degree to which transmission constraints in some areas result in a risk of insufficient resource *capacity* to meet the peak obligations. This need is in addition to that of unconstrained transmission areas with a short position, where PacifiCorp needs transfer balance.

In light of this new information, PacifiCorp is able to conclude that resource requirements in the Eastern control area are accelerated and in the Western control area are somewhat delayed, as compared with resources in the January IRP's Diversified Portfolio 1, the least cost, least risk, portfolio. PacifiCorp's ongoing request for proposal (RFP) process is expected to provide additional information regarding resource availability, costs and timelines to help fill the accelerated Eastern control area short position.

This IRP Update concludes with a status report on each of the Action Plan items identified in the January 2003 IRP. In addition, changes to the Action Plan that are warranted by the new information contained in this IRP Update are highlighted.

PacifiCorp has hosted three Quarterly Public Input Meetings and two Load-Forecasting Technical Workshops to inform IRP public input participants of changes to inputs and assumptions, and provide an update and status on the IRP Action Plan. This filing and the meetings with public input participants, provides PacifiCorp and interested parties with a new foundation for the 2004 IRP process, which begins December, 2003.

2. INPUTS AND ASSUMPTIONS

Since the IRP was filed in January, there have been updates to various inputs and assumptions. A comprehensive summary of updates can be found in the Appendix. Four of these updates were the main drivers to changes in the net position and the least-cost, low risk portfolio, Diversified Portfolio 1. The four updates include the Load Forecast, Hunter 4 Timing, topology, and market prices.

LOAD FORECAST

The long-term load forecast that is used in the IRP is updated every two years and represents a 20-year, hourly forecast of energy and demand use by customer class for each load center on PacifiCorp's system. The load forecast used in the filed IRP was prepared and released in 2001.

In May 2003, a new long-term load forecast was produced. The new forecast was based on the latest survey information, updated census data, and updated economic forecasts. In addition, there have also been changes to the way PacifiCorp develops a system peak forecast and hourly load forecasts. This new methodology is detailed below.

Forecasting Methodology

System Peak Forecast

The system peaks are the maximum loads required on the system in any 15-minute period. Originally, forecasts of the system peak for each month were prepared based on the load forecast produced using the methodologies described in Appendix K of the 2003 IRP. The peaks were then forecasted for two different times: the maximum usage on the entire system during each month (the coincidental system peak), and the maximum usage within each state during each month.

Currently, forecasts of the system peak are prepared based on forecasting individual state peaks and then aggregating these up to the system. Individual State peaks are calculated from the historic growths for summer and winter seasons separated for high load hours and super peak hours, over a 10-year period. The peaks are then extrapolated forward for each State, based on each State's historic growth pattern. In addition to historic peak growth rates, PacifiCorp also incorporated the current and forecasted saturation and penetration rates for each State (based on Commercial & Residential surveys conducted by PacifiCorp) to ensure proper growth rate changes out into the future.

The original method of calculating system peaks has been improved as a result of new State Hourly Models. The new methodology no longer requires monthly peak forecasts since the hourly model distributes load throughout the year to each hour providing annual shapes and monthly peaks based on historic information.

Hourly Load Forecasts

Originally, annual energy levels were spread to monthly values using historical consumption patterns. These were further distributed to daily and hourly shapes on historical consumption patterns.

Currently, the annual energy levels forecasts for each PacifiCorp jurisdiction are determined through the long-term forecast process, and are distributed using an hourly-shaping model, which distributes annual loads into each hour of each year. This is similar to the old method except that the model distributes an annual load, therefore not needing monthly values.

The hourly-shaping model is developed based on 3 years of historic consumption patterns and includes a number of spatial parameters for hours of day, days of week, weeks of year, as well as the months and seasons. In addition to these spatial parameters, there are also a number of temperature variables to capture load impacts resulting from temperature deviations from normal. The results of the shaping model also calibrates the peak and trough growth rate differentials based on history, which is calculated for each jurisdiction (as described in the System Peak Forecast Section). The use of the *hourly-shaping model* ensures that the monthly values align with historical load duration curves.

Overview of 2003 Long-Term Load Forecast

The 20-year long-term growth rate of the updated forecast is 2.5%, while the forecast used in the 2003 IRP had a long-term growth rate of 2.3%. Table 2.1 summarizes the differences of the long-term growth rates by state between the two forecasts. In the tables that follow, the forecast used in the 2003 IRP has been labeled as the 2001 Forecast because it was prepared and released in 2001 and the forecast developed in May 2003 is labeled as the 2003 Forecast.

Table 2.1 Percent per Year Growth Rates for Sales

State	2003 Forecast	2001 Forecast	Difference
Oregon	1.6%	2.0%	-0.4%
Washington	1.8%	2.0%	-0.2%
California	1.4%	1.3%	0.1%
Utah	3.5%	3.0%	0.5%
Idaho	0.9%	1.1%	-0.2%
Wyoming	1.8%	0.8%	1.0%
Totals	**2.5%**	**2.3%**	**0.2%**

There has been a shift in the forecast such that more growth is expected on the East side of the service area (Utah, Wyoming, Idaho) and less growth is expected on the West side of the service area (Oregon, California, and Washington).

The forecast for system peak demand has changed from 2.1% per year to 3.4% per year for the time period from 2003 through 2014. Table 2.2 summarizes the difference in the peak demand growth rates by state for the non-coincident peak demands.

Table 2.2 Percent per Year Growth Rates for Non-Coincident Peak Demand

State	2003 Forecast	2001 Forecast	Difference
Oregon	1.4%	1.8%	-0.4%
Washington	3.0%	1.8%	1.2%
California	2.2%	2.0%	0.2%
Utah	5.1%	2.7%	2.4%
Idaho	-0.1%	0.7%	-0.8%
Wyoming	1.7%	1.0%	0.7%
Totals	**3.4%**	**2.1%**	**1.3%**

State Summaries

Oregon

Table 2.3 summarizes Oregon's sales growth comparison by customer class for the 2003 Forecast and the 2001 Forecast.

Table 2.3 Forecast Comparison of Class Sales in Oregon

Class	2003 Forecast	2001 Forecast	Difference
Residential	1.1%	1.8%	-0.7%
Commercial	2.1%	2.1%	0.0%
Industrial	1.5%	2.3%	-0.8%
Irrigation	0.8%	0.3%	0.5%
Other	1.0%	0.9%	0.1%

The residential customer forecast in the 2003 Forecast projects a slower growth than for the 2001 Forecast primarily due to a lower expected population growth in the service area. Usage per customer in the residential class is less in the 2003 Forecast than in the 2001 Forecast. Usage per customer is declining in the 2003 Forecast due to expected appliance efficiency gains. Usage per customer was relatively constant for the 2001 Forecast. In summary, the residential class usage in the 2003 Forecast has a lower overall growth rate than the previous forecast.

Commercial customers are projected to grow slightly faster in the 2003 Forecast than in the 2001 Forecast due to an assumed faster growth in tourism-based industries. Usage per customer is projected to decline for the 2003 Forecast due to increased equipment efficiency. Usage per customer was relatively constant for the 2001 Forecast. The total effect on the commercial class is for the growth rate for each forecast to remain the same.

The industrial class is projected to grow slower in the 2003 Forecast than for the 2001 Forecast. The relative price of electricity is projected to increase at 0.4% per year in the 2003 Forecast. In the 2001 Forecast the relative price of electricity was projected to decline by 3.0% per year. This reversal of growth rates causes more fuel switching in the 2003 Forecast than assumed in the 2001 Forecast.

The difference in peak demand growth rates between the two forecasts follows the difference in the projected sales growth rates. The factors influencing the difference between the two forecasts' sales growth rates are also influencing the difference between the forecasted peak demand growth rates.

Washington

Table 2.4 summarizes Washington's sales growth comparison by customer class for the 2003 Forecast and the 2001 Forecast.

Table 2.4 Forecast Comparison of Class Sales in Washington

Class	2003 Forecast	2001 Forecast	Difference
Residential	1.3%	2.0%	-0.7%
Commercial	1.5%	2.0%	-0.5%
Industrial	2.9%	2.3%	0.6%
Irrigation	0.9%	0.3%	0.6%
Other	1.0%	1.4%	-0.4%

The slower rate of growth in the residential class is due to an assumed slower population growth in this part of PacifiCorp's service area. There is not a measurable difference in the usage per customer growth rates in the two forecasts. For both forecasts, the usage per customer is assumed to remain relatively flat.

The assumed slower population growth also affects the commercial sector. In addition, the 2003 Forecast has usage per customer declining over the forecast horizon due to equipment efficiency gains. The 2001 Forecast has usage per customer remaining relatively flat over the forecast horizon.

The industrial class is projected to grow at a faster rate in the 2003 Forecast than in the 2001 Forecast. Industrial production is projected to grow faster in the food, lumber, and paper industries in the state.

The differences in peak demand growth rates are due to several reasons. First, a higher conversion rate from evaporative coolers to central air conditioners is assumed. Second, more people per household are assumed in the 2003 Forecast than in the 2001 Forecast. Third, more air conditioning load was assumed in the 2003 Forecast.

California

Table 2.5 summarizes California's sales growth comparison by customer class for the 2003 Forecast and the 2001 Forecast.

Table 2.5 Forecast Comparison of Class Sales in California

Class	2003 Forecast	2001 Forecast	Difference
Residential	0.9%	1.6%	-0.7%
Commercial	2.2%	1.3%	0.9%
Industrial	0.0%	0.9%	-0.9%
Irrigation	1.1%	0.3%	0.8%

Other	0.7%	0.6%	0.1%

The slower rate of growth in the residential class is due to an assumed slower population growth in this part of PacifiCorp's service area. The 2003 Forecast has usage per customer declining over the forecast horizon due to appliance efficiency gains. The 2001 Forecast has usage per customer remaining relatively flat over the forecast horizon.

Customer growth for the commercial sector is the same in both forecasts. Usage per customer in the commercial sector is projected to increase in the 2003 Forecast primarily due to buildings constructed during the 1990s being larger than those built in the prior decade. This trend in larger buildings is expected to continue. Usage per customer was assumed to be relatively constant in the 2001 Forecast.

The peak demand in California is expected to grow slightly faster in the 2003 Forecast. The primary reason for this additional growth is the assumption that larger commercial buildings were built during the 1990s and the expectation that this trend is expected to continue.

Utah

Table 2.6 summarizes Utah's sales growth comparison by customer class for the 2003 Forecast and the 2001 Forecast.

Table 2.6 Forecast Comparison of Class Sales in Utah

Class	**2003 Forecast**	**2001 Forecast**	**Difference**
Residential	4.0%	2.9%	1.1%
Commercial	3.4%	3.0%	0.4%
Industrial	3.2%	3.3%	-0.1%
Irrigation	0.9%	0.2%	0.7%
Other	1.8%	0.8%	1.0%

The growth rate for residential customers is assumed to be the same for both forecasts. Usage per customer in the 2003 Forecast is increasing and was relatively flat in the 2001 Forecast. Two contributing factors to the increased usage are that newer homes are assumed to be larger, and that newer homes have more people per household. It is assumed that air conditioning saturation rates for single family and manufactured houses will be growing faster than assumed in the 2001 Forecast. Also, in the residential sector it is assumed that there is a switching of evaporative coolers for central air conditioning units.

The growth rate for commercial customers is assumed to be slightly less than the assumed growth rate in the 2001 Forecast. Usage per customer is projected to be increasing in the 2003 Forecast compared to slightly declining in the 2001 Forecast. Contributing to this increase is the assumption that newly constructed commercial structures have been larger. This trend is expected to continue in the 2003 Forecast.

The peak demand for the state of Utah is projected to have a higher growth rate in the 2003 Forecast than in the 2001 Forecast. The same factors which contribute to the increase in energy cause the summer peak demand to increase. However, most of the increase in energy occurs during the summer months due to the increase in residential air conditioning saturation and the switching from evaporative coolers to central units. These two factors when interacted with the larger structures and more people per household in the residential sector cause a faster increase in the summer hours than in the non-summer hours. These summer hours include the peak demand hour. The summer hours also tend to grow faster due to the larger structures in the commercial sector. The air conditioning saturation rate is larger than the electric heating saturation rate. So, the larger structures would have more of an impact on the summer hours than the non-summer hours.

Idaho

Table 2.7 summarizes Idaho's sales growth comparison by customer class for the 2003 Forecast and the 2001 Forecast.

Table 2.7 Forecast Comparison of Class Sales in Idaho

Class	2003 Forecast	2001 Forecast	Difference
Residential	1.7%	2.3%	-0.6%
Commercial	0.5%	0.4%	0.1%
Industrial	0.5%	0.4%	0.1%
Irrigation	1.6%	2.4%	-0.8%
Other	0.5%	0.6%	-0.1%

The forecast of residential sales is lower in the 2003 Forecast due to a projected lower growth rate of residential customers. This lower growth rate of residential customers is due to a lower expected population growth in the region.

The forecast of commercial sales is slightly higher in the 2003 Forecast than in the 2001 Forecast. The primary reason for this higher growth is that air conditioning usage is assumed to be higher in the 2003 Forecast than in the 2001 Forecast.

The peak demand is assumed to grow slower in the 2003 Forecast than in the 2001 Forecast. The major reason for this slower growth is the lower rate of residential customer growth assumed in the 2003 Forecast.

Wyoming

Table 2.8 summarizes Wyoming's sales growth comparison by customer class for the 2003 Forecast and the 2001 Forecast.

Table 2.8 Forecast Comparison of Class Sales in Wyoming

Class	2003 Forecast	2001 Forecast	Difference
Residential	0.3%	0.4%	-0.1%
Commercial	1.2%	1.2%	0.0%
Industrial	2.1%	0.8%	1.3%

Irrigation	0.3%	0.4%	-0.1%
Other	0.7%	0.0%	0.7%

The major difference in the Wyoming sales forecast is the industrial sales sector. Industrial growth in Eastern Wyoming is expected to be similar to the long-term historical trend growth. This difference also translates in the peak demand growth rate being higher in the 2003 Forecast than in the 2001 Forecast.

HUNTER 4 TIMELINE

In the original submittal of IRP Resources (Table C.18 Potential Supply Side Resources, page 209), Hunter Unit 4 was listed as having a lead-time of 48 months. This lead-time assumed a permit period of 9 months and a project completion period of 39 months. This schedule also assumed that internal approval was obtained before submittal of the permit application, and that a Certificate of Purpose and Necessity was obtained after internal approvals but before the submittal of the air permit application.

The IRP was clear in explaining the decision to proceed with a new coal plant would be different from the original 48-month assumptions. The filed IRP, on page 159, in Figure 9.3 introduces the concept of first obtaining the air permit for the coal plant, which may require a re-assessment of the cost. The cost reassessment must take into consideration any economic issues raised in obtaining an air permit including advances or changes in technology and the resulting risk assessment of those changes.

Other updates to the timeline include the NOI preparation time of three months, and the additional six months of air permitting time as indicated to PacifiCorp by UDAQ when the NOI was submitted. Finally, obtaining the Certificate of Purpose and Necessity after receiving the results of the air permit resulted in an additional 4 months to the timeline. These factors all add up to an overall addition of 13 months to the original 48-month timeline, for a total of 61 months.

The new 61-month schedule is shown in table 2.9 below. The studies and NOI preparation for Hunter 4 are already complete, and the NOI was filed with the Utah Department of Air Quality in May 2003. The timeline indicates that the original timeline for Hunter 4 (FY2008) is not a realistic goal for completion of a fourth unit at Hunter.

Table 2.9 Hunter 4 Timeline (months)

Option	Studies & NOI Preparation	Air Permitting	Certificate of Convenience & Necessity	Project Execution	Commissioning & Testing	Total Lead Time
Hunter 4	3	15	4	36	3	61

TOPOLOGY UPDATES

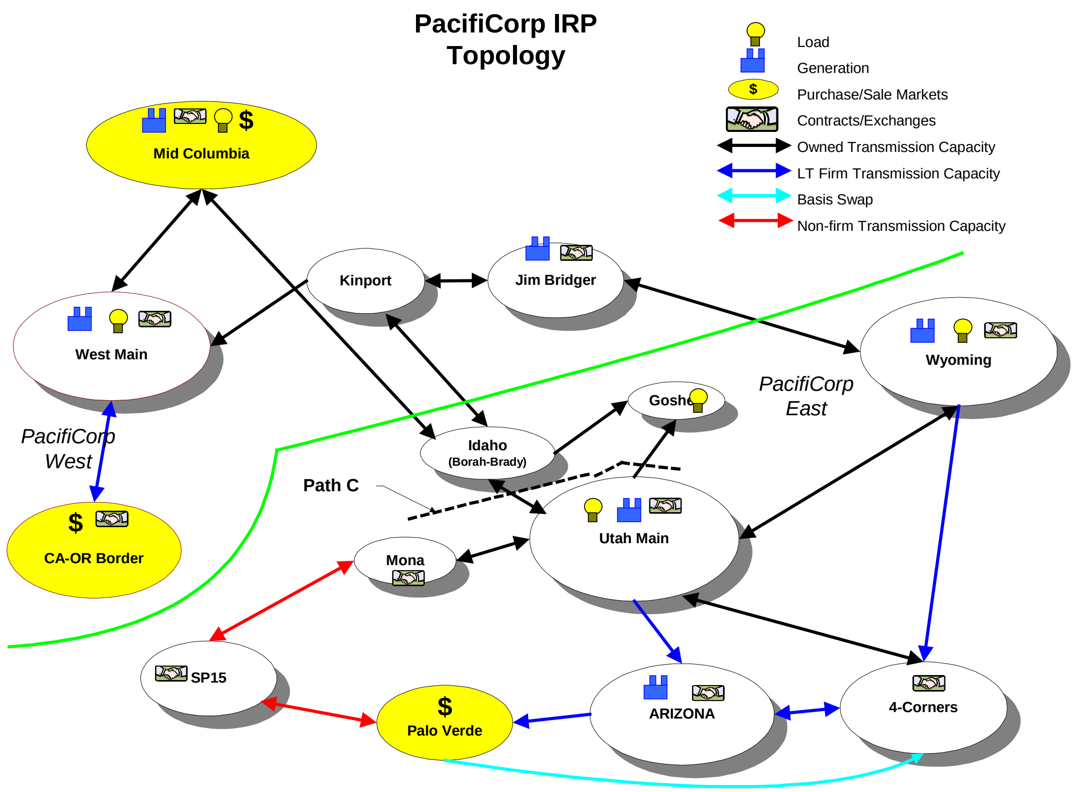
Since the publication of the 2003 IRP, PacifiCorp has modified its model topology. The following refinements provide improvements in model operation time and better represent transmission constraints and the access to markets available on the system. Each is discussed below.

First, the links between the Idaho, Kinport and Goshen bubbles were revised. Originally discussed at the July 21, 2003 IRP Quarterly Public Input Meeting, this revision better represents PacifiCorp's movement of electricity across Path C and corresponding unit dispatch.

Second, a number of transmission areas (bubbles) have been consolidated. The old topology was developed early in the IRP process. A highly refined topology was desired to capture the possible, but then unknown, resource locations. Since that time, PacifiCorp has obtained a better understanding of resource availability. Furthermore, a number of bubbles were found to provide no substantive information relevant to the modeling effort. Reducing the number of bubbles, speeds model simulation times.

Finally, a link has been added between Palo Verde and Four Corners. PacifiCorp serves its obligations at Four Corners through a combination of energy delivered from the Eastern Control Area and market purchases and physical swaps from other liquid points, like Palo Verde. The addition of this link improves the representation of how the Four Corners' obligations have historically been served.

Figure 2.1 Updated IRP Topology



MARKET UPDATES

Since the publication of the 2003 IRP, PacifiCorp updated its forecast of market prices for electricity and natural gas. The revised forecasts are summarized in the Appendix. The electricity market prices were prepared in a similar manner to those used for the January 2003 IRP. In the short run, the forecasts reflect recent forward prices evident in the marketplace. In the long run, the forecasts reflect updated information on recent and anticipated resource additions and transmission changes throughout the WECC. In addition, they incorporate a more recent forecast of natural gas prices, a primary driver of wholesale electricity prices.

The forecast of Western natural gas prices is higher than the base forecast of the January 2003 IRP. This outlook reflects recent market experience of high and volatile prices, underscoring the continuing challenge of maintaining North American natural gas production in the face of steeper declining rates in mature producing areas. In summary, the new base forecast for natural gas in the Northwest and Utah is about $0.40 per million British thermal units (MMBtu) higher over the 2005-2012 period. This is almost 10% higher than the January base forecast of about $4/MMBtu.

These gas price changes could alter the least-cost resource choices originally found in Diversified Portfolio 1. An example of the effect of higher natural gas prices on resource decisions is evident when evaluating the efficiency of a Combined-Cycle Combustion Turbine (CCCT) compared to a Simple Cycle Combustion Turbine (SCCT). The 2003 IRP originally assumed a preference for SCCTs (vs. CCCTs) when unit capacity factors were less than 30%. At current gas prices, CCCTs operate more economically at even lower capacity factors. This is one of the reasons that the ‘Addition Type’ column in the Action Plan (see Chapter 4) has been updated with more generic wording for action items 15 and 16.

3. Net Position

PacifiCorp's net position drives resource decisions. The size and timing of new resource decisions hinge upon PacifiCorp's obligations delineated by the net position.

Since the IRP was filed in January, PacifiCorp has spent a considerable amount of time validating the model against actual system operations data, and synchronizing near term operations with long-term IRP planning efforts. This work resulted in both an updated net position and an enhanced way of representing the position.

EVALUATION OF SHORT POSITION

Analysis of the new position revealed a need to segment the short position by location. The reason for this change is that the new load forecast and an evaluation of the transmission system highlighted an issue related to delivering resources in a transmission-constrained area. Therefore, it was important to have the ability to review these areas of the system and analyze them in more granularity.

This approach differs from the filed IRP. The 2003 IRP first took an energy view of each control area, and then analyzed the capacity position for the total system with a 15% planning margin target. The new approach breaks the system into more detail and looks at the position as two Tier's, based on constraints. The tiered approach is consistent with the manner in which PacifiCorp's Front Office plans for the system in the near term (2-3 years out).

Tier 1 Position

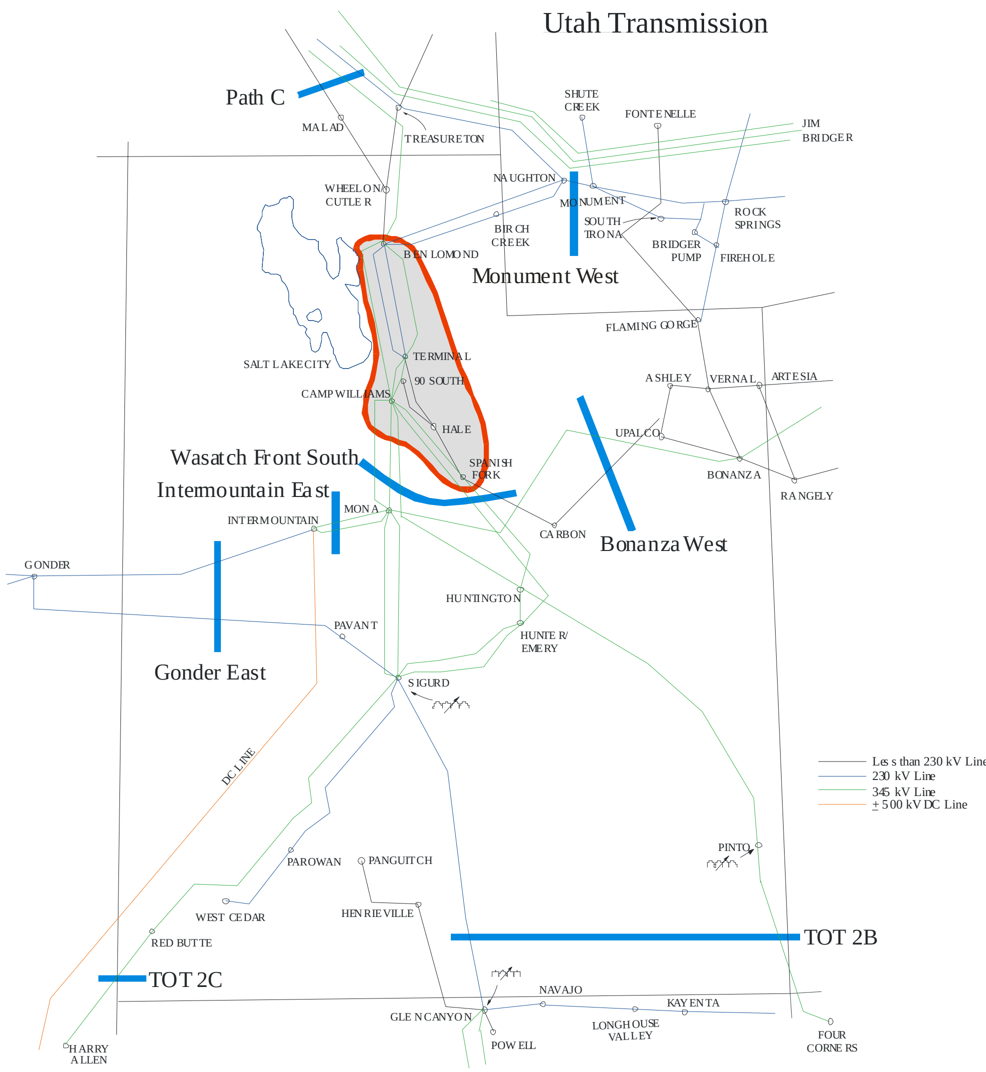
Tier 1 is defined as the risk of insufficient resource capacity within a transmission-constrained area to meet the maximum firm capacity obligation. For a Tier 1 position PacifiCorp will plan to cover the peak hour physical position with average annual unplanned outages for the area.

Tier 1 of PacifiCorp's position resides in the Utah 'Bubble'. The Utah 'Bubble' is defined by loads, resources, and contracts in Southeast Idaho, Utah and Southwest Wyoming (west of Naughton). The Utah 'Bubble' fits the Tier 1 definition since transmission constraints in this area limit firm import capability.

The transmission constraint was first identified in the 2003 IRP process and was called the "Mona Triangle" constraint. Item #27 of the Action Plan (pg. 157) specified preparing detailed plans to implement the "Wasatch Front Triangle" transmission upgrades. The new load forecast increased the importance of reviewing the "Mona or Wasatch Front Triangle". The review highlighted that PacifiCorp has limited import capability from the south, and that load growth may cause the need to expand transmission import capability.

After reviewing the Mona triangle, PacifiCorp defined the Wasatch Front South (WFS) import boundary. This boundary refers to the transfer capability of six transmission lines allowing imports of power from south to north into the Wasatch Front. The figure below illustrates the WFS boundary.

Figure 3.1 Wasatch Front South Boundary



Sixty percent of PacifiCorp's resources are located south of the WFS boundary, and ninety-five percent of PacifiCorp's load resides north of the boundary. All power flowing from the south must flow across this constrained area.

Retaining flexibility from the south is important. In addition to the majority of PacifiCorp's resources falling south of the constraint, the liquid markets such as Palo Verde, SP15 and Four Corners are also to the south. Flexibility is necessary when events such as unforeseen load excursions, or generation and transmission outages occur. Furthermore, access to liquid markets improves net power costs by enhancing the ability to make purchases or sales when economic.

The new load forecast and an evaluation of the transmission system highlight the importance of Tier-1 issues. The next step involves assessing the size and timing of PacifiCorp's Tier-1 position. This in turn leads to a discussion of the solutions available to resolve it.

Table 3.1 Tier-1 Position

Item	FY05	FY06	FY07	FY08	FY09	FY10
	CY04	CY05	CY06	CY07	CY08	CY09
Peak Load	(4,940)	(5,160)	(5,367)	(5,602)	(5,898)	(6,115)
Firm Imports	1,219	1,119	1,119	1,119	1,119	1,119
Resources * (net reserves)	3,670	3,542	3,546	3,399	3,531	3,607
Outage	(550)	(550)	(550)	(550)	(550)	(550)
Net Position	(601)	(1,049)	(1,252)	(1,634)	(1,798)	(1,939)

Planning efforts for Tier-1 risks are best managed through a targeted approach. Only geographically specific, physical solutions resolve Tier-1 short positions. Potential solutions include additions of DSM, generation delivered within the constrained area and/or transmission. PacifiCorp is currently engaged in RFP efforts, which will directly impact the Tier-1 position. The outcome of these efforts will drive future planning efforts.

Tier 2 Position

PacifiCorp's remaining short position is classified as "Tier 2". The definition of a Tier 2 position is when PacifiCorp has insufficient energy resources in an unconstrained area. The Tier 2 position does not face the same capacity limitations and delivery risk observed in Tier 1. Accordingly, it is measured in a less strict manner. Instead of a single, peak hour evaluation, traditional hourly load and resource duration curves are presented. These curves were common to many of the discussions surrounding the development of the IRP. Under this study, two load centers are considered Tier 2: the West Control Area and Four Corners.

Tier 2 - PacifiCorp West Control Area Position

Figure 3.2, below, illustrates the Tier 2 position of PacifiCorp's West Control Area in FY2005. It is important to understand the composition of these figures. First, the curves assume no explicit planning margin. However, they include allotments for reserves and forced outages. Extreme hours, like reality, feature multiple forced outages. The duration curves are presented after transfers between the control areas. Most importantly, the Figures simulate system dispatch without access to market. Denying market access presents a picture of the system's native ability to serve its obligations.

Figure 3.2 PacifiCorp West Net Position Duration Curve (FY2005)

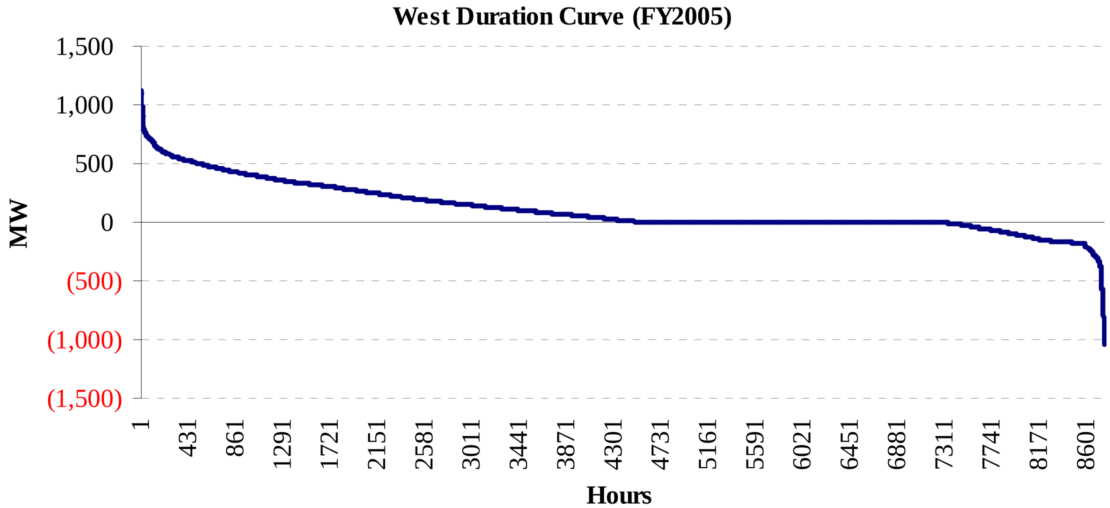


Figure 3.2 presents the West system in essentially three states:

- *Surplus:* During ~48% of the year, the system is surplus. Over these hours the West has more than sufficient native resources to serve the obligations within the control area. Alternatively stated, surplus capacity, net of the reserves obligation, is held idle during this period.

- *Flat:* Within the next section, representing ~30% of the year, the West control area is flat. Here the West has served all of its native obligations and then transferred surpluses to the East. The size and duration of these transfers varies.

- *Short:* The Western system is short for the balance of the year. This short position exceeds 90 MW for 10% of the year. Excursions, observed on the far right of the Figure are largely contingency driven.

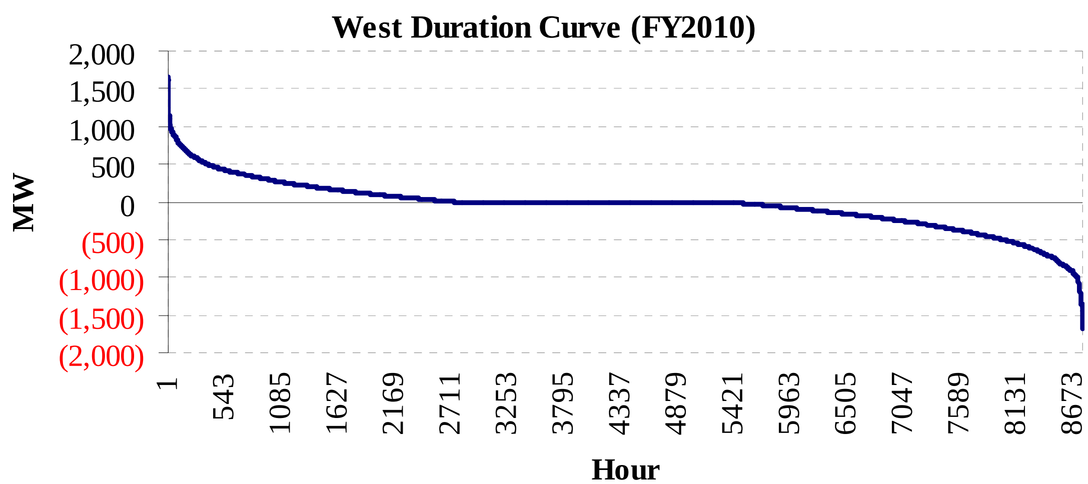
The FY2005 position leads to three conclusions. First, the West is essentially resource sufficient for the early years of the planning period. This is particularly true in light of the West's access to market (not represented here). Sufficient import capability exists to serve the small duration of deficit position as well as deal with contingencies should they arise. Second, the West has sufficient capacity to support both its indigenous peak requirements as well as the peak requirements of the East at the limits allowed by transmission. Finally, the West had sufficient resources to maximize transfers to the East at or near the limits of PacifiCorp's firm rights. However, the high level of transfers is limited to select hours.

Figure 3.3 illustrates the West position in FY 2010. Like FY 2005, the diagram can be broken into three sections.

- *Long:* The West is long ~20% of the year. Compared to 2005, this period of length has declined.
- *Flat:* Transfers flatten the West's position for ~20% of the year. This period has similarly narrowed since 2005.
- *Short:* The West is short, to some extent, nearly 50% of the year. At the tail, the short position exceeds 425 MW for ~20% of the time.

The combination of fundamental load growth and contract expirations creates this growing deficit. Given the late date of this position, it is likely that no action to resolve it will be necessary until the next planning cycle.

Figure 3.3 PacifiCorp West Net Position Duration Curve (FY2010)



As with 2005, transfers between the East and the West provide important information. Over the summer peak hours in 2010, transfers remain high. However, the total energy transferred during the year declines substantially. In addition to the capacity requirements noted earlier, additions of energy to the West would likely be beneficial. Additions of energy could broaden the period of such transfers. Additional energy would also help native balancing requirements otherwise served from market. Such a requirement may be a good candidate for low-cost, intermittent resources such as wind.

Tier 2 - Four Corners Position

Four Corners holds the final short position of note. PacifiCorp maintains significant long-term contractual obligations at Four Corners. While PacifiCorp does not serve native load in that area, the size and duration of the position merits addressing it as a Tier 2 concern.

The position is principally driven by a seasonal exchange contract. The contract creates an obligation (short) in the summer and a resource (length) in the winter. Size and time of the position can be substantial. Over peak summer hours the obligation can exceed 400 MW. Historically, PacifiCorp served this obligation with a combination of power from the East control area, purchases at Four Corners, and physical swaps from more liquid points (like Palo Verde). Solutions to the Four Corners short position also emerge from the on-going RFP process.

REVISIONS TO DIVERSIFIED PORTFOLIO 1

The 2003 IRP prescribed a slate of resources to resolve PacifiCorp's short position. Table 3.2 below, summarizes these resources. As the name implies, the portfolio was diversified. It featured a blend of new thermal, renewable and DSM resources. Thermal generation included simple cycle combustion turbines, combined cycle plants, and pulverized coal. The portfolio was also geographically diverse with large allocations of new generation installed in both control areas.

Table 3.2 Diversified Portfolio I

	Diversified Portfolio I Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
East	Thermal contract (installed capacity in MW)	-	-	25.00	25.00	25.00	-	25.00	25.00	25.00	25.00	175.00
	Class 1 DSM (load control - peak MW capability)	30.00	30.00	31.00								91.00
	Class 2 DSM (MWa added each year)	30.00	12.00	11.00	12.00	12.00	12.00	12.00	12.00	12.00	-	123.00
	Wind (East - installed capacity in MW)				200.00		200.00		200.00		120.00	720.00
	Super Peak Contract	225.00				(225.00)						-
	Coal Base Load (Hunter 4)					575.00						575.00
	CCCT (Mona)									480.00		480.00
	CCCT (Gadsby Repower)						510.00					510.00
	Peaker East (Mona)										200.00	200.00
	Reserve Peakers (East)			200.00							300.00	500.00
West	Thermal contract (installed capacity in MW)	-	-	25.00	25.00	25.00	-	25.00	25.00	25.00	25.00	175.00
	Class 2 DSM (MWa added each year)	5.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	-	22.00
	Wind (West - installed capacity in MW)			100.00		200.00		200.00		200.00		700.00
	Flat Contract (7X24)								200.00			200.00
	3-Year Flat Off-Peak	500.00			(500.00)							-
	CCCT (Albany)				570.00							570.00
	Reserve Peakers (West)			230.00						230.00		460.00
	Peaking Contract									100.00		100.00

Diversified Portfolio 1 is no longer well aligned with PacifiCorp's updated position. Four main reasons drive a need to revise the plan. First, demand growth has changed. Second, new information regarding the resource lead times has emerged. Third, the approach to planning margin has evolved. Finally, the RFP process is expected to provide additional information regarding resource availability, costs and timelines. Each is discussed below.

Diversified Portfolio 1 generally balanced new resources between the East and West control areas. With the new load forecast, the demand-related needs in the West diminished and those in the East rose. Accordingly, the next planning cycle is expected to find greater resource needs in the East control area (particularly Utah) and less resource needs in the West. However, while the West's demand growth is smaller than expected by the 2003 IRP, resource losses due to contract expirations remain the same. Therefore, latter years will likely retain some form of resource requirement in the West.

In addition to redistributing resources, updated plans must account for revised lead-times. Discussed previously, the 2003 IRP timelines for the installation of Hunter-4 and transmission upgrades north of Mona cannot be completed as originally expected due to the revised permitting and construction schedules. Both resources were key elements of the original Action Plan. With revised availability schedules, DP1 must also be revised.

The 2003 IRP proposed building the system to a 15% planning margin. Diversified Portfolio 1 was developed accordingly. Discussed earlier, the position is now evaluated using a two-tier approach. For purposes of assessing PacifiCorp's requirement, the evaluation accounts for reserves and forced outages. This approach better links planning targets with system operations. However, the approach makes no explicit assumptions/additions for planning margin. If appropriate, decisions regarding planning margin and other resource sufficiency issues will be addressed in the next planning cycle.

Finally, the 2003 IRP presented a plan featuring proven technologies at known sites. The approach facilitated the development of reasonable cost data for evaluation. The RFP process, now underway, is expected to provide PacifiCorp with new resources as well as a host of cost and availability information. DP1 will need to be revised in light of this new information.

SUPPLY AND DEMAND ALTERNATIVES

As PacifiCorp enters the new planning cycle, efforts to satisfy the Tier-1 and Tier-2 requirements will be important. Some efforts are already underway. Others will begin in the next year. Additional actions may be warranted by the findings of the next IRP. The following information reviews some of the actions available to PacifiCorp. These outcomes will inform and serve as the basis for the development of the Integrated Resource Plan scheduled for publication in December 2004.

The RFP 2003-A, issued in June 2003, sought to procure a slate of resources specified by Diversified Portfolio 1. The process continues. During the solicitation of proposals, PacifiCorp notified participants that additional, Utah delivered resources will be considered in light of the updated load forecasts and as such the economic size of resources should not be constrained in the RFP process. Increasing the acquisition scope of RFP 2003-A seeks to resolve the large Tier-1 position arising from the new load forecast.

The 2003 IRP Action Plan prescribed the issuance of a renewable RFP (RFP 2003-B). Given the requirements observed within both control areas, RFP-2003-B will be issued as planned. Stated throughout the IRP process, a procurement strategy, more aggressive than specified by DP1, may be pursued if economic.

Particularly in light of the large Tier-1 position, DSM remains an important alternative in the search for new resources. A DSM RFP was issued in June 2003. Both the contracted solutions and information learned from the RFP will be valuable contributors to resolving PacifiCorp's load and resource gap.

The customer will be an important element of the solutions implemented by PacifiCorp. Both customer education and rate-design alternatives are being and will continue to be explored in the future.

Findings this summer highlighted the importance of transmission solutions. PacifiCorp is now researching and analyzing transmission investments in the Mona Triangle. PacifiCorp is also actively exploring economic alternatives within sub-regional transmission planning efforts.

Qualifying Facilities (QF's) may meet part of PacifiCorp's requirement. Interest from QF developers has risen over the past several months. The potential for new QF's is promising. While PacifiCorp does not know the business plans of specific developers and cannot predict the introduction of new QF's or control their delivery timing, it does recognize that they could be part of the solution.

Mentioned in this update and in the 2003 IRP, the West control area, in particular, is subject to expiring supply contracts. Renegotiation of those contracts could provide an important resource solution to PacifiCorp.

PacifiCorp remains constrained by both resource development timelines and the large size of new resource alternatives. Near term purchases fill the gaps between resource introductions. Such purchases were an important, early resource component of DP1. They will remain an important alternative in the future.

RFP 2004-A is in response to a need identified by the 2003 IRP. While this RFP will not be issued until next year, it is important. This RFP will seek to procure resources for CY2008 and beyond.

4. ACTION PLAN UPDATE

This section provides an overview of the updated IRP Action Plan. The 'STATUS/UPDATE' column summarizes specific progress or information updates to each action.

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS/UPDATE
Base Load West	1. Prepare detailed plans, including: an economic review and justification for building a base load CCCT in the West of the system, level of resources needed, and the procurement date. The review will address: • The merits, risks and benefits of negotiating alternative PPA agreements following the expiration of existing contracts in the West • The potential and options for negotiating additional capacity associated with the existing BPA contract.	The revised load resource balance and resulting west Tier 2 position shows that there is no need for a baseload resource by FY2007. Re-evaluating the timing and need for a base load unit in the West.
Base Load – East by FY2008	2. Procure a base load unit in the East of the system for operation by FY2008. Prepare detailed plans including a review and justification for building or buying the base load unit. Prepare detailed plans including a review and justification for building or buying the base load coal unit in the East of the system for FY2008. The review will include, but will not be limited to: • An economic review for selecting coal as the fuel • Alternative fuel options including natural gas • Emissions Impacts on the surrounding area • Other existing or partially developed sites • Alternative PPA agreements with appropriate credit worthy counter-parties	RFP 2003 A targeted to procure a base load unit in this timeframe.
Base Load East	3. Continue environmental permitting activity for Hunter 4 to ensure this base load plant option is available for implementation and operation in or after FY2009. [1]	Filed for NOI on May 8 with the UDAQ.

[1] This action item not in agreement with the Oregon Acknowledgement Order (Docket LC 31).

ADDITION TYPE	**IMPLEMENTATION ACTIONS**	**STATUS/UPDATE**
Base Load	4. Procure a base load unit in the East of the system for operation in or after FY2009.[2] Prepare detailed plans including a review and justification for building or buying the base load coal unit in the East of the system. The review will include, but will not be limited to: • An economic review for selecting coal as the fuel • Alternative fuel options including natural gas • Emissions Impacts on the surrounding area • Other existing or partially developed sites • Alternative PPA agreements with appropriate credit worthy counter-parties	RFP 2004 A targeted to procure a base load unit in this East.
DSM	5. Design and determine the cost effectiveness of the proposed Air Conditioning Load Control program in Utah. Launch and implement the Air Conditioning Load Control program as appropriate and in line with the findings.	Complete. Cool Keeper program launched in May, 2003. Over 6,000 customers have agreed to join the program to date. UT Schedule 114 was filed 4/9/03, and was effective 5/14/03.
DSM	6.Design and determine the cost effectiveness of the proposed refrigerator re-cycling program. Launch and implement the refrigerator re-cycling program as appropriate and in line with the findings.	Complete. See 'ya later Refrigerator program launched in June, 2003. UT Schedule 117 was filed 5/5/03 and was effective 6/16/03. Program progressing well.

[2] This action item not in agreement with the Oregon Acknowledgement Order (Docket LC 31).

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS
DSM	7. Design and determine the cost effectiveness of the proposed efficient central air conditioner program. Launch and implement the efficient central air conditioner program as appropriate and in line with the findings.	Complete. Cool Cash program launched in May, 2003. UT Schedule 113 was filed 2/21/03 and was effective on 3/24/03.
DSM	8. Complete an evaluation of the available, realistic CHP sites and market size throughout the PacifiCorp territory.	Utah Complete. Primen study being purchased to complete system market assessment.
DSM	9. Implement and operate the specific DSM programs in the D-P40 decrement that was included DPI. This will build 150 MWa DSM between 2004 and 2014.	Complete. Programs are continuing operation.
DSM	10. Conduct an Economic and Market Potential study throughout the PacifiCorp Service territory to determine the magnitude of the DSM opportunities available to PacifiCorp, including Oregon Class 1, 3 and 4 DSM resources.	Actually available market being determined through the RFP process.
DSM	11. Design a “bundle” of cost effective DSM programs that build to an additional 300 MWa between 2004 and 2014 in line with the decrement options reviewed in the IRP.	Being completed through the DSM RFP process.
DSM	12. Prepare, issue and implement a Request For Proposals (RFP) for 100 MWa of Class 2 DSM for implementation commencing early 2004 as part of the “bundle’ of options in action item 11.	DSM RFP 2003 was issued June 26, 2003. Responses received Au. 18, 2003. Short listed proposals are under evaluation.
DSM	13. Determine revised DSM targets for the period 2004 to 2014 based on the results of action items 10, 11 and 12.	Will be completed after RFP results are complete.

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS
DSM	14. Evaluate and implement as appropriate the irrigation load control program in Idaho for 2004.	Complete. ID Schedule 72 issued 1/31/03, effective 3/17/03. Pricing and curtailment for summer '03 complete.
Flexible Resources (Daily Dispatchable) - FY2006	15. Procure flexible resources (daily dispatchable) for the East side of the system for operation in FY2006. Develop detailed plans and proposals, including the timeline for delivery, for flexible resources required for the East side of PacifiCorp's system for FY2006.	Re-evaluating the timing and need for flexible resources in the West. RFP 2003 A targeted to procure flexible resources in the East.
Flexible Resources	16. Review the West Valley plant performance and requirement and negotiate the West Valley plant terms and conditions in line with the existing lease contract arrangements.	Scheduled to be evaluated in the next IRP Planning cycle.
Renewables	17. Evaluate expansion options for PacifiCorp's Blundell Geothermal plant and implement expansion if appropriate and cost effective.	Currently evaluating a 10 – 12 MW expansion at Blundell.
Renewables	18. Prepare, issue and implement an RFP for wind generation on the West of the system in line with the proposed procurement pattern: • 100 MW – FY2006 • 200 MW - FY2008 • 200 MW - FY2010 Move up acquisition dates if RFP process reveals it is economic to do so.	RFP 2003 B targeted to procure renewables for both the West and East sides of the system.

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS
Renewables	19. Prepare, issue and implement an RFP for wind generation on the East of the system in line with the proposed procurement pattern: • 200 MW – FY2007 • 200 MW – FY2009 • 200 MW – FY2011 Move up acquisition dates if RFP process reveals it is economic to do so.	RFP 2003 B targeted to procure renewables for both the West and East sides of the system.
Renewables	20. Prepare, issue and implement an RFP for renewable generation options (i.e. geothermal, solar, fuel cells) which could be implemented in addition to, or as an alternative to, the proposed wind build pattern modeled in DP1 (Action Items 18 and 19).	RFP 2003 B is scheduled to be issued by the end of CY2003.
Shaped Products	21. Determine the strategy and negotiate, as appropriate, asset based shaped product contracts to fill: • The super-peaking needs in the East of the system for 2004/05/06/07 • Thermal asset based contracts in support of the capacity requirements to achieve the appropriate planning margin established through Implementation Action 24 on both the East and West of the system. • Thermal asset based contracts (25 MW) to support the addition of profiled wind in the East and West of the system.	Still evaluating planning margin and capacity credit for wind (see Item 24). RFP 2003 A targeted to procure super-peaking needs for the designated timeframe.
Strategy and Policy	22. Determine the long term IRP model(s) including a review of options for using optimization logic for future IRP’s	Currently reviewing solutions from two vendors (Henwood & MS Gerber). Will incorporate optimization logic in next planning cycle.

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS
Strategy and Policy	23. Agree any changes to Standards and Guidelines that may impact the implementation of the IRP Action Plan	Currently, participating in open dockets in OR &WA to revue S&G. Will continue to be proactive about participating in state discussions as they materialize.
Strategy and Policy	24. Determine the Planning Margin PacifiCorp will adopt if different from the 15% planning margin adopted in this IRP. The analysis for this will include loss of load probability studies.	Scheduled to be evaluated in the next IRP Planning cycle.
Transmission	25. Detail and commission selected transmission power system analysis studies to support the implementation of the IRP Action Plan. The studies will provide greater detail on transmission costs associated with all the portfolio additions.	Interconnection and system impact studies are being requested in line with resources being analyzed in RFP 2003-A and RFP 2003-B.
Transmission	26. Prepare detailed plans including an economic review and justification and apply for necessary transmission upgrades to support asset additions.	Interconnection and system impact studies are being requested in line with resources being analyzed in RFP 2003-A and RFP 2003-B.

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS
Transmission	27. Prepare detailed plans including an economic review and justification to implement the “Wasatch Front Triangle” transmission upgrades.	Review is currently underway in conjunction with RFP 2003-A.
Transmission	28. Review options for firming up the IRP non-firm transmission requirement.	Requests for firm transmission are being drafted for submittal to transmission organizations.
DSM	29. For the next IRP or Action Plan brought forward for the Commission's acknowledgment, assess Class 1, Class 3 and Class 4 demand-side management resources in Oregon, include in the portfolios those resources that are least cost, and include in the load forecast the likely impacts from implementation of DSM programs.	Scheduled to be evaluated in the next IRP Planning cycle.
DSM	30. If the Company's demand response assessment due year-end indicates new voluntary demand response pilots or programs are cost-effective now or build capability for the future, bring them forward by March 31, 2004, for the Commission's consideration with a proposed effective date of May 1, 2004.	Using the RFP process and decrement analysis to evaluate the cost-effective opportunity.
Renewables	31. Perform studies on the capacity value for wind resources and determine the appropriate level for use in the next IRP or Action Plan requiring Commission action.	Study to commence after the filing of Action Plan update, to be delivered in the next planning cycle.

Appendix

The appendix provides an overview of updates to inputs and assumptions in Appendix C of the filed 2003 IRP. Table headings and numbers are consistent with what was originally published in Appendix C.

Table C.12 annual Average Natural Gas Prices

Annual Average Natural Gas Prices MidC & Utah ($/MMBtu)		
Fiscal Year	**Mid C**	**Utah**
2005	$4.62	$4.53
2006	$4.48	$4.34
2007	$4.56	$4.42
2008	$4.62	$4.47
2009	$4.72	$4.56
2010	$4.52	$4.35
2011	$4.22	$4.02
2012	$4.20	$3.99
2013	$4.33	$4.12
2014	$4.31	$4.10
2015	$4.04	$3.82
2016	$4.26	$3.94
2017	$4.52	$4.18
2018	$4.74	$4.38
2019	$4.87	$4.51
2020	$5.01	$4.63
2021	$5.11	$4.72
2022	$5.14	$4.76
2023	$5.29	$4.89
2024	$5.43	$5.02

Figure C.1 Annual Average Natural Gas prices

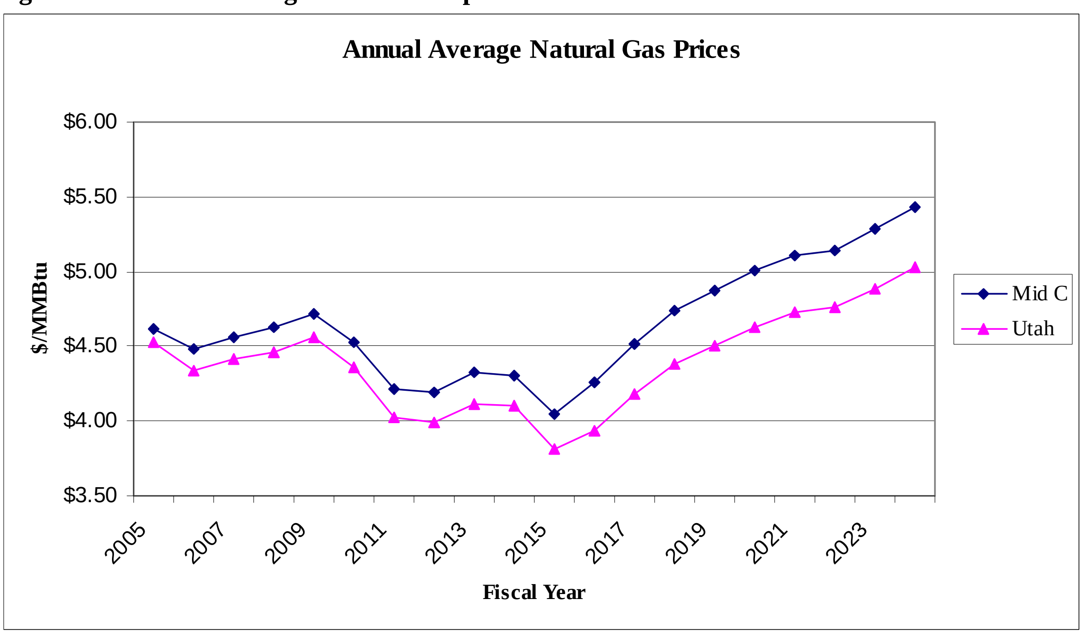


Table C.13 Annual Average Coal Prices for each of the PacifiCorp owned plants

Annual Average Delivered Coal Price by Plant
($/MMBtu)

Fiscal Year	Cholla	Colstrip	Carbon	Hunter	Huntington	Hayden	Craig	Bridger	Johnston	Naughton	Wyodak
2004	$1.33	$0.67	$0.72	$0.87	$0.83	$1.09	$0.99	$0.91	$0.54	$1.03	$0.61
2005	$1.37	$0.68	$0.76	$0.86	$0.84	$1.09	$0.99	$0.91	$0.60	$1.04	$0.63
2006	$1.42	$0.70	$0.59	$0.84	$0.98	$1.05	$1.04	$0.97	$0.60	$1.07	$0.65
2007	$1.45	$0.72	$0.59	$0.79	$0.96	$0.93	$1.02	$0.99	$0.61	$1.09	$0.66
2008	$1.48	$0.74	$0.60	$0.85	$0.79	$0.94	$1.04	$1.01	$0.63	$1.13	$0.68
2009	$1.56	$0.76	$0.63	$0.89	$0.85	$0.95	$1.07	$0.82	$0.65	$1.15	$0.70
2010	$1.55	$0.78	$0.64	$0.91	$0.84	$0.91	$1.09	$0.85	$0.66	$1.18	$0.72
2011	$1.58	$0.80	$0.65	$0.94	$0.87	$0.93	$1.11	$0.86	$0.68	$1.21	$0.73
2012	$1.61	$0.82	$0.67	$0.95	$0.90	$0.95	$1.09	$0.88	$0.69	$1.25	$0.75
2013	$1.64	$0.85	$0.68	$0.97	$0.88	$0.95	$1.12	$0.91	$0.71	$1.28	$0.77
2014	$1.67	$0.86	$0.69	$0.99	$0.90	$0.97	$1.14	$0.93	$0.72	$1.31	$0.79
2015	$1.71	$0.88	$0.71	$1.01	$0.91	$0.99	$1.16	$0.95	$0.74	$1.33	$0.80
2016	$1.74	$0.90	$0.72	$1.03	$0.93	$1.01	$1.19	$0.97	$0.75	$1.36	$0.82
2017	$1.78	$0.92	$0.74	$1.05	$0.95	$1.03	$1.21	$0.99	$0.77	$1.39	$0.84
2018	$1.81	$0.94	$0.75	$1.08	$0.97	$1.05	$1.24	$1.01	$0.78	$1.41	$0.85
2019	$1.85	$0.95	$0.76	$1.10	$0.99	$1.07	$1.26	$1.03	$0.80	$1.44	$0.87
2020	$1.88	$0.97	$0.78	$1.12	$1.01	$1.09	$1.29	$1.05	$0.81	$1.47	$0.89
2021	$1.92	$0.99	$0.80	$1.14	$1.03	$1.12	$1.31	$1.07	$0.83	$1.50	$0.91
2022	$1.96	$1.01	$0.81	$1.16	$1.05	$1.14	$1.34	$1.09	$0.85	$1.53	$0.92
2023	$2.00	$1.03	$0.83	$1.19	$1.07	$1.16	$1.36	$1.11	$0.86	$1.56	$0.94

Table C.14 Thermal Plant Heat Rates
FY 2003 Budget Revised Heat Rate Targets

	Units	CB1	CB2	Cholla4	Colstrip3	Colstrip4	Craig1	Craig2	DJ1	DJ2	DJ3	DJ4	GA1	GA2
100% Capacity														
Net Dependable Rating, 100%	MW	67	105	380	740	740	428	428	106	106	220	330	60	75
Minimum	MW	20	30	300	245	245	130	130	25	25	70	120	17	20
PacifiCorp Share of Capacity														
%	$	100%	100%	100%	10%	10%	19%	19%	100%	100%	100%	100%	100%	100%
Net Dependable Rating	MW	67	105	380	74	74	83	83	106	106	220	330	60	75
Minimum	MW	20	30	300	25	25	25	25	25	25	70	120	17	20
Heat Rate														
100% Load	MW	67.00	105.00	380.00	740.00	740.00	428.00	428.00	106.00	106.00	220.00	330.00	60.00	75.00
100% Heat Rate	BTU/KWh	11,842	10,835	10,514	18,776	18,970	13,123	13,123	11,230	11,230	11,062	11,128	13,183	11,619
85% Load	MW	56.95	89.25	323.00	629.00	629.00	363.80	363.80	90.10	90.10	187.00	280.50	51.00	63.75
85% Heat Rate	BTU/KWh	11,960	10,928	10,546	17,189	17,383	12,489	12,489	11,183	11,183	11,121	11,196	13,158	11,719
70% Load	MW	46.90	73.50	266.00	518.00	518.00	299.60	299.60	74.20	74.20	154.00	231.00	42.00	52.50
70% Heat Rate	BTU/KWh	12,160	11,099	10,682	15,614	15,808	11,868	11,868	11,230	11,230	11,262	11,356	13,273	11,946
55% Load	MW	36.85	57.75	209.00	407.00	407.00	235.40	235.40	58.30	58.30	121.00	181.50	33.00	41.25
55% Heat Rate	BTU/KWh	12,509	11,415	11,008	14,061	14,255	11,272	11,272	11,450	11,450	11,552	11,683	13,645	12,406
Minimum Load	MW	20.00	30.00	300.00	245.00	245.00	130.00	130.00	25.00	25.00	70.00	120.00	17.00	20.00
Minimum Heat Rate	BTU/KWh	14,044	13,012	10,585	11,894	12,088	10,444	10,444	13,929	13,929	12,784	12,635	16,209	15,291

Note: CB = Carbon
DJ = Dave Johnston
GA = Gadsby

Table C.14 Thermal Plant Heat Rates (continued)

	Units	GA3	Hayden1	Hayden2	HR1	HR2	Hunter1	Hunter2	Hunter3	HN1	HN2	JB1	JB2	JB3
100% Capacity														
Net Dependable Rating, 100%	MW	100	184	262	237	237	430	430	460	440	455	530	530	530
Minimum	MW	25	73	103	153	153	200	200	160	220	220	200	200	200
PacifiCorp Share of Capacity														
%	$	100%	25%	13%	100%	100%	94%	60%	100%	100%	100%	67%	67%	67%
Net Dependable Rating	MW	100	45	33	237	237	403	259	460	440	455	353	353	353
Minimum	MW	25	18	13	153	153	187	121	160	220	220	133	133	133
Heat Rate														
100% Load	MW	100.00	184.00	262.00	237.00	237.00	430.00	430.00	460.00	440.00	455.00	530.00	530.00	530.00
100% Heat Rate	BTU/KWh	11,308	12,914	16,735	7,197	7,179	10,420	10,263	10,502	10,260	10,202	10,585	10,287	10,573
85% Load	MW	85.00	156.40	222.70	201.45	201.45	365.50	365.50	391.00	374.00	386.75	450.50	450.50	450.50
85% Heat Rate	BTU/KWh	11,449	12,293	15,492	7,317	7,292	10,526	10,262	10,532	10,274	10,204	10,489	10,270	10,479
70% Load	MW	70.00	128.80	183.40	165.90	165.90	301.00	301.00	322.00	308.00	318.50	371.00	371.00	371.00
70% Heat Rate	BTU/KWh	11,659	11,697	14,261	7,605	7,519	10,710	10,311	10,614	10,361	10,278	10,470	10,312	10,461
55% Load	MW	55.00	101.20	144.10	130.35	130.35	236.50	236.50	253.00	242.00	250.25	291.50	291.50	291.50
55% Heat Rate	BTU/KWh	11,995	11,148	13,050	8,200	7,953	11,036	10,452	10,790	10,581	10,479	10,588	10,463	10,582
Minimum Load	MW	25.00	73.00	103.00	153.00	153.00	200.00	200.00	160.00	220.00	220.00	200.00	200.00	200.00
Minimum Heat Rate	BTU/KWh	13,954	10,688	11,830	7,775	7,645	11,334	10,605	11,391	10,705	10,641	11,109	10,938	11,109

Note: GA = Gadsby
HR = Hermiston
HN = Huntington
JB = Jim Bridger

Table C.14 Thermal Plant Heat Rates (continued)

	Units	JB4	NT1	NT2	NT3	WY	GA4-6	WV1-5
100% Capacity								
Net Dependable Rating, 100%	MW	530	160	210	330	335	40	40
Minimum	MW	200	80	105	200	180	10	10
PacifiCorp Share of Capacity								
%	$	67%	100%	100%	100%	80%	100%	100%
Net Dependable Rating	MW	353	160	210	330	268	40	40
Minimum	MW	133	80	105	200	144	10	10
Heat Rate								
100% Load	MW	530.00	160.00	210.00	330.00	335.00	40.00	40.00
100% Heat Rate	BTU/KWh	10,606	10,639	10,606	10,440	11,746	10,108	10,108
85% Load	MW	450.50	136.00	178.50	280.50	284.75	34.00	34.00
85% Heat Rate	BTU/KWh	10,503	10,700	10,655	10,471	11,868	10,500	10,500
70% Load	MW	371.00	112.00	147.00	231.00	234.50	28.00	28.00
70% Heat Rate	BTU/KWh	10,471	10,820	10,758	10,575	12,049	11,083	11,083
55% Load	MW	291.50	88.00	115.50	181.50	184.25	22.00	22.00
55% Heat Rate	BTU/KWh	10,571	11,050	10,959	10,810	12,335	12,011	12,011
Minimum Load	MW	200.00	80.00	105.00	200.00	180.00	10.00	10.00
Minimum Heat Rate	BTU/KWh	11,054	11,168	11,063	10,701	12,367	17,395	17,395

Note: JB = Jim Bridger
NT = Naughton
WY = Wyodak
WV = West Valley

Table C.18 Potential Supply Side Resources

Supply Side Resources													
	Fuel	Installation Location	Technology	Plant Lead Time - Months	Capacity MW	Maximum Capacity Addition per Site	Capital Cost in $/kW (Average)	Annual Heat Rate HHV	Maint. Outage Rate (1-EAF-EFOR)	Equivalent Forced Outage Rate (EFOR)	Fuel Cost $/mmBtu	Var. O&M $/MWh	Fixed O&M in $/kW-yr
East Side Options (4500'):													
Coal													
Extend Existing Carbon Units 10 years	Utah Coal	Utah	PC-Sub	0	175	0	$42	11,350	4.30%	4.7%	$0.61	$0.25	$54.50
Hunter 4 - PC	Utah Coal	Utah	PC-Sub	61	575	575	$1,389	9,483	5.00%	4.0%	$0.72	$0.73	$27.39
Utah Greenfield PC	Utah Coal	Utah	PC-Sub (2x500)	72	575	1,150	$1,431	9,483	5.00%	4.0%	$1.00	$0.73	$33.94
Utah Greenfield IGCC	Utah Coal	Utah	IGCC - 7FA (2x1)	78	370	740	$1,797	8,311	15.00%	10.0%	$1.00	$1.83	$25.94
Wyoming Greenfield PC	PRB	Wyoming	PC-Sub - PRB	78	575	1,150	$1,501	9,483	5.00%	4.0%	$0.84	$0.73	$33.94
Natural Gas													
Microturbines	Nat. Gas	Utah	Capstone	12	0.020	0.204	$2,312	14,321	1.00%	1.0%	Nat. Gas	$7.93	$433.25
Fuel Cells	Nat. Gas	Utah	SOFC (Westinghouse)	12	0.225	2	$1,500	5,688	1.00%	1.0%	Nat. Gas	$2.13	$53.78
Extend Existing Gadsby Units 10 years	Nat. Gas	Utah	Steam Boilers	0	235	235	$9	12,950	1.01%	3.7%	Nat. Gas	$0.10	$27.61
Utah CHP (Cogen. - CT)	Nat. Gas	Utah	7FA (1x1) - 100K Steam	38	190	190	$957	7,136	4.10%	4.6%	Nat. Gas	$1.94	$13.14
Utah CHP (Non CT)	Nat. Gas	Utah	Topping Turbine	24	25	50	$659	5,305	5.00%	10.0%	Nat. Gas	$0.15	$25.69
Greenfield SCCT Aero	Nat. Gas	Utah	SCCT - 2 - LM6000	12	80	400	$718	10,233	0.02%	10.2%	Nat. Gas	$3.90	$11.45
Greenfield SCCT Frame (2 7FA - 5100 feet)	Nat. Gas	Utah	SCCT - 1 - 501D5	24	280	1,120	$532	10,467	5.25%	2.8%	Nat. Gas	$9.67	$10.39
Brownfield SCCT Frame	Nat. Gas	Utah	SCCT - 1 - 501D5	24	100	400	$532	10,467	5.25%	2.8%	Nat. Gas	$3.14	$11.23
Gadsby Repowering (2x1) - 4250 feet (Wet Cooling)	Nat. Gas	Utah	CCCT - 7FA (2x1)	41	450	450	$710	6,948	5.25%	2.8%	Nat. Gas	$2.42	$9.76
Gadsby Repowering Duct Firing (2x1)	Nat. Gas	Utah	2-7FA Duct Firing	41	110	110	$193	8,857	5.25%	2.8%	Nat. Gas	$0.10	$2.73
Greenfield CCCT 2x1 - 5100 feet (Dry Cooling)	Nat. Gas	Utah	CCCT - 7FA (2x1)	33	420	840	$767	7,192	5.25%	2.8%	Nat. Gas	$2.47	$11.87
Greenfield CCCT Duct Firing 2x1	Nat. Gas	Utah	7FA Duct Firing	33	105	210	$203	9,345	5.25%	2.8%	Nat. Gas	$0.10	$2.87
Greenfield CCCT 2-2x1 - 5100 feet (Dry Cooling)	Nat. Gas	Utah	CCCT - 7FA (2x1)	33	840	1,680	$648	7,192	5.25%	2.8%	Nat. Gas	$2.43	$8.12
Greenfield CCCT Duct Firing 2-2x1	Nat. Gas	Utah	7FA Duct Firing	33	210	420	$203	9,345	5.25%	2.8%	Nat. Gas	$0.10	$2.87
Other - Renewables													
Wind - Wyoming (36% CF)	n/a	Wyoming	1650 kW machines	12	50	200	$1,000	n/a	n/a	n/a	n/a	$0.00	$22.65
Wind - Utah (30%)	n/a	Utah	1650 kW machines	12	50	200	$1,000	n/a	n/a	n/a	n/a	$0.00	$22.65
Blundell Upgrade	Geothermal	Utah	K-ST	24	50	50	$1,880	10,000	4.13%	0.9%	$18/MWh	$0.10	$16.00
Pumped Storage	Water/coal	Nevada	Pumped Hydro	36	200	400	$850	13,924	n/a	n/a	$1.00	$0.51	$10.00
Solar	Solar	Utah	Thermal (Solar II)	48	200	200	$5,028	n/a	n/a	n/a	n/a	$0.20	$41.18

Technology Code:		
	PC-Sub	Pulverized Coal - Subcritical
	IGCC	Intergrated Gasification Combined Cycle (Clean Coal Tech.)
	SCCT	Simple Cycle Combustion Turbine
	CCCT	Combined Cycle Combustion Turbine
	CCCT	Repower Combined Cycle
	K-ST	Kalina based Steam Turbine
	Cogen	Cogeneration
	Renewables	
	Elevation Correction Factor for east to west	1.13

Table C.18 Potential Supply Side Resources (continued)

Supply Side Resources														
	Fuel	Installation Location	Technology	Plant Lead Time - Months	Capacity MW	Maximum Capacity Addition per Site	Capital Cost in $/kW (Average)	Annual Heat Rate HHV	Maint. Outage Rate (1-EAF-EFOR)	Equivalent Forced Outage Rate (EFOR)	Fuel Cost $/mmBtu	Var. O&M $/MWh	Fixed O&M in $/kW-yr
West Side Options (1500')													
Natural Gas													
Microturbines	Nat. Gas	Northwest	Capstone	12	0.023	0.231	$2,046	14,321	1.00%	1.0%	Nat. Gas	$7.93	$433.25
Fuel Cells	Nat. Gas	Northwest	SOFC (Westinghouse)	12	0.225	2	$1,500	5,688	1.00%	1.0%	Nat. Gas	$2.13	$53.78
West Side CHP (Cogen. CT)	Nat. Gas	Northwest	501D5 - 200,000 lb/hr	38	212	212	$856	7,136	5.25%	2.8%	Nat. Gas	$1.94	$13.14
West Side CHP (Non CT)	Nat. Gas	Northwest	Topping Turbine	24	25	50	659	5,305	5.00%	10.0%	Nat. Gas	$0.15	$25.69
Greenfield SCCT Aero	Nat. Gas	Northwest	SCCT - 2 - LM6000	12	90	450	$643	10,233	0.02%	10.2%	Nat. Gas	$3.52	$10.13
Greenfield SCCT Frame	Nat. Gas	Northwest	SCCT - 1 - 501D5	24	115	460	$458	10,467	5.25%	2.8%	Nat. Gas	$8.72	$9.94
Greenfield CCCT 2x1	Nat. Gas	Northwest	CCCT - 7FA (2x1)	33	474	948	$680	7,192	5.25%	2.8%	Nat. Gas	$2.59	$10.52
Greenfield CCCT Duct Firing 2x1	Nat. Gas	Northwest	Duct Firing - 7FA	33	118	236	$180	9,345	5.25%	2.8%	Nat. Gas	$0.10	$2.54
Other - Renewables													
West Side Wind (30% CF)	n/a	Northwest	Stateline Econ.	12	50	300	$1,000	n/a	n/a	5.0%	n/a	$0.00	$22.65

Technology Code:	PC-Sub	Pulverized Coal - Subcritical
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	CCCT	Repower Combined Cycle
	K-ST	Kalina based Steam Turbine
	Cogen	Cogeneration
	Renewables	
	Elevation Correction Factor for east to west	1.13

Table C.18 Potential Supply Side Resources (continued)

Supply Side Resources									
Emissions									
	Minimum Load as a percent of Capacity	Minimum Time to Full Load in Minutes (Warm Start)	Average Down Time in Minutes	Cost per Startup	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu	Comments
East Side Options (4500'):									
Coal									
Extend Existing Carbon Units 10 years	25%	180	720	$6,558	0.640	0.420	2.2	204	Startup Costs based on Unit 2 - assumes no new emission controls
Hunter 4 - PC	25%	240	720	$21,407	0.059	0.072	0.6	204	Costs based on Hunter 4 Consortium Proposal
Utah Greenfield PC	25%	240	720	$3,755	0.059	0.072	0.6	204	Costs based on modified Hunter 4 Consortium Proposal
Utah Greenfield IGCC	25%	360	720	$2,403	0.030	0.050	0.6	204	Assume Technology not available for decision till 2006
Wyoming Greenfield PC	25%	240	720	$3,755	0.059	0.072	1.5	204	Costs based on modified Hunter 4 Consortium Proposal
Natural Gas									
Microturbines	25%	5	240	$2,631	0.00147	0.1006	0.255	118	Base on RAMPP6 - no escalation
Fuel Cells	25%	30	240	$2,631	0.00147	0.0039	0.255	118	Based on Westinghouse CHP250 System - Available post 2005
Extend Existing Gadsby Units 10 years	25%	120	720	$2,631	0.00147	0.080	0.255	118	Base Startup and EFOR Values on Unit 3 (20010921)
Utah CHP (Cogen. - CT)	25%	25	60	$6,241	0.00147	0.1006	0.255	118	Taken from past Gadsby Repowering (1x1) before it was removed from list
Utah CHP (Non CT)	25%	120	480	$658	0.00147	0.0800	0.255	118	Base on RAMPP6 with no escalation (50 MW during planning horizon)
Greenfield SCCT Aero	25%	10	30	$3,257	0.00147	0.0181	0.255	118	Costs assume a minimum of two machines (HR assumes compressor)
Greenfield SCCT Frame (2 7FA - 5100 feet)	25%	25	60	$13,253	0.00060	0.0323	0.255	118	Costs based on two machines (HR assumes compressor)
Brownfield SCCT Frame	25%	25	60	$13,253	0.00060	0.0323	0.255	118	DLN NOx control only (Maximum CF of 20%)
Gadsby Repowering (2x1) - 4250 feet (Wet Cooling)	25%	120	480	$13,724	0.00060	0.0110	0.255	118	
Gadsby Repowering Duct Firing (2x1)	25%	20	0	$0	0.00060	0.0110	0.255	118	Only Available with Gadsby Repower
Greenfield CCCT 2x1 - 5100 feet (Dry Cooling)	25%	130	480	$13,724	0.00060	0.0110	0.255	118	
Greenfield CCCT Duct Firing 2x1	25%	20	0	$0	0.00060	0.0110	0.255	118	Only Available with CCCT
Greenfield CCCT 2-2x1 - 5100 feet (Dry Cooling)	25%	130	480	$27,448	0.00060	0.0110	0.255	118	Not available till 2006
Greenfield CCCT Duct Firing 2-2x1	25%	20	0	$0	0.00060	0.0110	0.255	118	Only Available with CCCT
Other - Renewables									
Wind - Wyoming (36% CF)	5%	10	0	$0	0.00000	0.0000	0.000	0	Based on 8/27/02 NWPPC work - not including tax credit or dispatch cost
Wind - Utah (30%)	5%	10	0	$0	0.00000	0.0000	0.000	0	Based on 8/27/02 NWPPC work - not including tax credit or dispatch cost
Blundell Upgrade	25%	60	240	n/a	0.00000	0.0000	0.000	0	Mac Crosby 04/09 (Steam cost estimated 25% less than current $24/MWh)
Pumped Storage	20%	15	480	$0	0.10000	0.4000	3.000	204	Capacity Factor limited to 17% - cost based on system average coal
Solar	25%	60	720	$0	0.00000	0.0000	0.000	0	Based on lowest pure Solar option from RAMPP6 (Solar II - 63% CF)

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	CCCT	Repower Combined Cycle
	K-ST	Kalina based Steam Turbine
	Cogen	Cogeneration
	Renewables	
	Elevation Correction Factor for east tc	1.13

Table C.18 Potential Supply Side Resources (continued)

Supply Side Resources									
Emissions									
	Minimum Load as a percent of Capacity	Minimum Time to Full Load in Minutes (Warm Start)	Average Down Time in Minutes	Cost per Startup	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu	Comments
West Side Options (1500')									
Natural Gas									
Microturbines	25%	5	240	$2,631	0.00147	0.0800	0.255	118	Base on RAMPP6 - no escalation
Fuel Cells	25%	30	240	$0	0.00147	0.0039	0.255	118	Base on RAMPP6 - no escalation
West Side CHP (Cogen. CT)	25%	25	60	$6,241	0.00147	0.1006	0.255	118	Uses Utah CHP (Cogen. - CT) information from above
West Side CHP (Non CT)	25%	120	480	$658	0.00147	0.08000	0.255	118	Base on RAMPP6 with no escalation (50 MW during planning horizon)
Greenfield SCCT Aero	25%	10	30	$3,664	0.00147	0.01810	0.255	118	Based on East numbers adjusted by elevation factor
Greenfield SCCT Frame	25%	25	60	$4,682	0.00060	0.03230	0.255	118	Based on East numbers adjusted by elevation factor
Greenfield CCCT 2x1	25.0%	130	480	$13,724	0.00060	0.0110	0.255	118	Based on Utah numbers adjusted by elevation factor
Greenfield CCCT Duct Firing 2x1	25.0%	20	0	$0	0.00060	0.0110	0.255	118	Based on Utah numbers adjusted by elevation factor
Other - Renewables									
West Side Wind (30% CF)	5%	10	0	$0	0.00000	0.000	0.0	0	Based on 8/27/02 NWPPC work - not including tax credit or dispatch cost

Technology Code:	PC-Sub	Pulverized Coal - Subcritical	
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	CCCT	Repower Combined Cycle	
	K-ST	Kalina based Steam Turbine	
	Cogen	Cogeneration	
	Renewables		
	Elevation Correction Factor for east tc		1.13

Table C.26 Wholesale Market Prices

Flat Prices (7X24)		Medium Price Forecast		
Fiscal Year Period		COB	PV	MidC
Apr-04	Mar-05	$ 43.05	$ 41.98	$ 39.29
Apr-05	Mar-06	$ 41.10	$ 39.96	$ 37.67
Apr-06	Mar-07	$ 41.96	$ 40.47	$ 38.31
Apr-07	Mar-08	$ 43.55	$ 39.98	$ 40.68
Apr-08	Mar-09	$ 45.54	$ 40.84	$ 43.96
Apr-09	Mar-10	$ 47.49	$ 41.85	$ 47.16
Apr-10	Mar-11	$ 48.33	$ 42.73	$ 48.45
Apr-11	Mar-12	$ 48.40	$ 43.30	$ 48.47
Apr-12	Mar-13	$ 47.79	$ 43.48	$ 47.59
Apr-13	Mar-14	$ 48.50	$ 44.42	$ 48.23
Apr-14	Mar-15	$ 49.32	$ 45.62	$ 49.06
Apr-15	Mar-16	$ 50.62	$ 47.23	$ 50.23
Apr-16	Mar-17	$ 51.20	$ 48.21	$ 51.34
Apr-17	Mar-18	$ 55.31	$ 51.59	$ 54.76
Apr-18	Mar-19	$ 57.53	$ 53.44	$ 57.26
Apr-19	Mar-20	$ 60.16	$ 55.76	$ 59.90
Apr-20	Mar-21	$ 61.05	$ 57.06	$ 60.91
Apr-21	Mar-22	$ 61.49	$ 57.21	$ 61.24
Apr-22	Mar-23	$ 63.33	$ 58.92	$ 63.08
Apr-23	Mar-24	$ 65.24	$ 60.69	$ 64.97
Apr-24	Mar-25	$ 67.19	$ 62.51	$ 66.92
Apr-25	Mar-26	$ 69.21	$ 64.38	$ 68.93
Apr-26	Mar-27	$ 71.28	$ 66.32	$ 71.00
Apr-27	Mar-28	$ 73.42	$ 68.31	$ 73.13
Apr-28	Mar-29	$ 75.62	$ 70.36	$ 75.32
Apr-29	Mar-30	$ 77.89	$ 72.47	$ 77.58
Apr-30	Mar-31	$ 80.23	$ 74.64	$ 79.91
Apr-31	Mar-32	$ 82.64	$ 76.88	$ 82.30
Apr-32	Mar-33	$ 85.12	$ 79.19	$ 84.77