- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PACIFICORP, dba Utah Power & Light Company, for Approval of Standard Rates for Purchases of Power from Cogeneration Qualifying Facilities Having a Design Capacity of 1,000 Kilowatts or Less or Small Power Production Qualifying Facilities Having a Design Capacity of 3,000 Kilowatts or Less	))))))))))	DOCKET NO. 06-035-T06 ORDER

ISSUED: September 12, 2006

SHORT TITLE

Update of Electric Service Schedule No. 37 Rates for Power Purchases from Qualifying Facilities.

SYNOPSIS

The Commission does not approve the rates as filed. PacifiCorp is directed to refile Schedule No. 37 rates and tariff sheets with the adjustments noted herein.

By The Commission:

INTRODUCTION AND PROCEDURAL BACKGROUND

On July 12, 2006, PacifiCorp, dba Utah Power & Light Company ("PacifiCorp" or "Company"), filed proposed changes to Electric Service Schedule No. 37 of Tariff P.S.C.U. No. 46 of Utah Power & Light Company. Schedule No. 37 establishes standard prices for purchases of power from Utah-located cogeneration Qualifying Facilities ("QFs") with a design capacity of 1,000 Kilowatts (kW) or less and small power production QFs with a design capacity of 3,000 Kilowatts (kW) or less. The rates are based on avoided costs developed from the Company's Integrated Resource Plan ("IRP"). Avoided costs are costs the Company would incur to serve its native load "but for" the generation provided by the QFs. Schedule No. 37 prices are also used to evaluate special contracts, demand side resource programs and form the basis of credits paid under Electric Service Schedule No. 135, the Company's Net Metering Service. Specifically, the Company updates the rates for known and expected changes to system costs and requests a change to the definition of peak hours. On July 17, 2006, the Commission requested the Utah Division of Public Utilities ("Division") investigate and review the proposed changes. On August 4, 2006, the Division filed its review and recommendations. No other party provided comments.

DISCUSSION, FINDINGS AND CONCLUSIONS

The Company's filing of July 12th provides a calculation of avoided costs using the method approved in Docket No. 03-035-T10. That method differentiates between periods of resource sufficiency and deficiency. Resource deficiency is marked by resource deficit in annual energy, and both summer and winter peak loads. During resource deficiency, avoided capital and energy costs are estimated by a proxy plant. The Company represents this deficiency occurs in 2012. From 2006 to 2011, the system has sufficient energy and winter capacity and is deficit only in summer. Consistent with the method approved in Docket No. 03-035-T10, avoided energy cost from 2006 through 2011, is calculated using the Company's production cost model, GRID. The avoided energy cost is calculated as the difference in energy cost between the existing system and the cost that occurs when a 10 MW zero cost resource is added to the Company's system resources. The avoided summer capacity cost is based on the fixed cost plus variable operation and maintenance cost of a simple cycle combustion turbine ("SCCT"). A blending of the expected costs of a combined cycle combustion turbine ("CCCT") with duct-firing and a coal-fired resource is used to estimate avoided capacity and energy costs beginning in 2012 and for the remaining years of the calculation.

For the purpose of comparing the proposed Schedule No. 37 rates to existing Schedule No. 37 rates, the Company levelizes the annual prices using an assumed capacity factor over a 20-year contract starting in 2006. This levelized price, assuming an 85 percent capacity factor, is $51.85 per megawatt hour. This proposed rate is one percent higher than the current levelized rate of $51.22 per megawatt hour for the 2006 to 2025 period. On an annual basis, the proposed rates in comparison to current rates are 8% lower in 2006, 6% to 23% higher in years 2007 to 2011, and 3% to 12% lower in years 2012 to 2025.

In this filing, the Company also proposes to change the definition of holidays which are treated as off-peak power days. Pioneer Day, July 24, and President's Day, are removed from the list of holidays and therefore treated like any other day for the purpose of defining peak hours. Further, the Company removes language allowing the Friday before a holiday (if the holiday falls on a Saturday) to be counted as the holiday. The Division concurs with these changes but also recommends that peak hours be further defined by time zone. The Division states the time zone assumed in defining peak hours as 6:00 am to 10:00 pm is Pacific Prevailing Time rather than Mountain Prevailing Time. To avoid confusion, the Division recommends the time zone distinction be added to the schedule language. We concur and direct the Company to make this change. Specifically, we order the Company to define peak hours using Mountain Prevailing Time and to denote it as such. We also note for correction an error on tariff sheet 37.4; levelized prices shown are the existing Schedule No. 37 prices rather than the prices proposed in this filing.

Any estimation of avoided costs requires assumptions of the Company's future loads and resources, the least-cost plant's type, cost and characteristics, inflation and discount rates, natural gas prices, and wholesale power prices. We review these assumptions and inputs to insure they are consistent with the Company's integrated resource plan and result in reasonable measures of avoided costs over the 20-year time horizon.

Load and Resource Balance

The Company's load and resource balance is based on its updated 2004 Integrated Resource Plan ("2004 IRP Update") filed in Utah, November 2005. The 2004 IRP Update includes changes to the load and resource balance used in PacifiCorp's 2004 IRP Report. The 2004 IRP Update load and resource balance is further adjusted in this filing. Changes include use of the Company's March 31, 2006, in-house projections of natural gas and power prices as well as use of the February 27, 2006, long-term natural gas forecast of its consultant, PIRA Energy Group. Long-term sales and purchase contracts are also updated to include information available as of June 2006, including the following long-term purchase contracts: AMPS Resources (Cove Fort), Constellation p268849, Idaho RTSA, Schwendiman QF, ExxonMobil QF, Monsanto Curtailment, Weyerhauser Reserve, PSCo Exchange, two UBS purchases and five Morgan Stanley purchases. The load forecast also differs from the 2004 IRP Update; the proposed load and resource balance is based on the Company's May, 2006, load forecast being used in the Company's 2006 IRP analysis now underway. The new load and resource balance shows a summer peak deficit beginning in 2007, and a surplus in winter peak and annual energy until January 2012.

The Division states it is uncomfortable with adopting avoided resources from an IRP Update that has not been acknowledged by the Commission but recommends no changes to the load and resource balance assumptions. The Division supports use of the new load forecast because it better reflects the Company's current view of its resource needs and when these resources will be needed. Based on the Company's representation these changes in inputs and assumptions are reasonable, and finding no specific objections, we accept use of these changes for calculating avoided costs in this docket.

Avoidable Resource Type, Cost, and Characteristics

During the years 2006 to 2011, PacifiCorp proposes to make a summer capacity payment based on the number of deficit months in the year. The Company uses the estimated capital cost and fixed and variable operation and maintenance costs of an SCCT from its 2004 IRP Update to value monthly capacity payments from 2006 to 2011. The Company proposes payments based on 4, 7, 4, 3, 5, 9 months of capacity deficit in years 2006 through 2011 respectively. The Division provides no comment on the number of months identified as resource constrained. Based on the Company's representation the number of months proposed are reasonable, and finding no objections, we accept use of the Company's proposed number of months for calculating avoided costs in this docket.

In the 2004 IRP Update, the Company identifies two resources as least cost to meet the 2012 resource deficit: a coal-fired resource located in Utah and a CCCT resource located in the Northwest. The Company proposes to blend the costs of these two resources to represent proxy plant cost. For avoided capacity cost, the two resource costs are blended using nameplate capacity and for avoided energy cost, costs and heat rates are blended using annual generation of coal-fired and natural gas-fired resources estimated in a GRID evaluation of thermal generation from 2006 to 2025.

The Division does not comment on the method of blending and presents no recommended changes. Based on the Company's representation its method of blending costs is reasonable, and finding no objections, we accept the Company's method of blending for use in calculating avoided costs in this docket.

For proxy plant capital and operations and maintenance costs during the period of resource deficiency, the Company assumes a brownfield, subcritical, coal-fired resource located in Utah and a wet-cooled, greenfield CCCT with duct-firing capability located in Utah, adjusted for altitude.

The Division provides no specific comment on the reasonableness of these assumptions and does not recommend any change to these assumptions. We note the 2004 IRP Update selects a supercritical rather than subcritical coal-fired plant in Utah and shows cost differences for northwest and Utah CCCT resources not reflected in the Company's proposed proxy plant costs. The Company and Division provide insufficient explanation for the deviations. We direct the Company to revise Schedule No. 37 rates to comport with the cost assumptions of a supercritical coal-fired resource located in Utah and a wet-cooled greenfield CCCT resource with duct firing capability in the northwest, consistent with the 2004 IRP Update least-cost portfolio.

Coal Prices

Coal prices in 2006 and 2007 are from the Company's most current near term coal price forecasts. The Company estimates coal prices in 2006 and 2007 to be $0.96 per million British thermal units ("BTU") and $1.06 per million BTU respectively. Coal prices after 2007 are Company projections prepared and used in its 2004 IRP Update. They begin at $1.14 per million BTU and escalate 2 to 7 percent per year.

The Division does not recommend any change to the coal price projections but objects to the use of purely forecasted fuel prices in the production cost analysis to determine avoided energy cost during the period of resource sufficiency. The Division recommends the Company use actual fuel costs when available in order to make the near term avoided costs as accurate as possible. Specifically, the Division recommends any existing fuel contracts held by the Company, either gas or coal, should be included in the avoided cost run. We concur and direct the Company to make the appropriate changes to Schedule No. 37 rates. Based on the Company's representation these coal price forecasts are reasonable, and finding no objections, we accept use of the forecasts for calculating avoided cost in this docket.

Natural Gas Prices

The Company's forecast is a combination of its own projections of natural gas prices, based on market data, through April 2012, and long-term price projections from the forecasting firm of PIRA Energy Group ("PIRA") to 2020. The two sources are blended in equal portions from May 2012 to April 2013. From May 2013 through 2020 the forecasts are from PIRA and for the remaining years the 2020 PIRA monthly forecasts are escalated using an inflation factor from the 2004 IRP Update. The natural gas prices begin in 2006 at $7.02 per million BTU and escalate to $8.28 per million BTU in 2007. The prices then decline annually until 2013 to a forecast value of $5.58 per million BTU, and then escalate for the remaining years. The average annual escalation for the twenty year period from 2006 to 2025 is 1.45 percent per year.

The Division provides no review of the reasonableness of these forecasts nor recommends any change to the forecasts. However, as discussed above regarding coal prices, the Division objects to the use of purely forecasted fuel prices in the near term when contract prices, rather than projected prices, may be known. We agree and direct the Company to use actual natural gas contract prices in the GRID calculation of avoided energy cost. Absent actual contract prices and based on the Company's representation that its natural gas price forecasts are reasonable, and finding no objections, we accept the use of these natural gas price forecasts for calculating avoided cost in this docket.

Wholesale Power Prices

Wholesale power prices from 2006 to April 2012, are Company in-house projections derived from market data dated March 31, 2006. From May 2012, to April 2013, wholesale power prices are a 50 - 50 blending of this data set with results from the Company's market-price clearing model, MIDAS. From May 2013 and beyond, the wholesale power price projections are 100 percent derived by the MIDAS model. The MIDAS model natural gas price assumptions appear to be consistent with the natural gas price forecasts and blending of natural gas price forecasts described earlier.

The Division does not recommend any change to these wholesale power price projections. Based on the Company's representation these wholesale power price forecasts are reasonable, and finding no objections, we accept use of the wholesale power price forecasts for calculating avoided costs in this docket.

ORDER

NOW, THEREFORE, PURSUANT TO OUR DISCUSSION, FINDINGS AND CONCLUSIONS MADE HEREIN, WE ORDER:

The avoided cost rates, terms and conditions contained in PacifiCorp's application to change rates for Electric Service Schedule No. 37, P.S.C.U. Tariff 45 are not approved as filed. The Company is directed to refile the rates and tariff sheets with the adjustments noted herein. Specifically, these adjustments are: 1) On-peak hours shall be defined using Mountain Prevailing Time and denoted as such; 2) the cost of the coal and natural gas resources identified as proxy plants beginning in 2012 shall be consistent with the least cost portfolio identified by the Company in its 2004 IRP Update; 3) the costs of actual fuel contracts held by the Company, either natural gas or coal, shall be used in the GRID calculation of avoided energy cost. In the absence of actual contract prices, forecasted fuel prices shall be used.

The Company shall submit to the Commission the appropriate tariff sheets for Electric Service Schedule No. 37 that reflect the decisions made herein. The Division shall review the revised sheets for compliance with this Order.

DATED at Salt Lake City, Utah, this 12th day of September, 2006.

/s/ Ric Campbell, Chairman

/s/ Ted Boyer, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#50461