- 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 Qualifying Facilities Having a Design Capacity of 1,000 Kilowatts or Less	))))))	DOCKET NO. 03-035-T10 ORDER

ISSUED: June 1, 2004

By The Commission:

INTRODUCTION AND PROCEDURAL BACKGROUND

On January 30, 2004, 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. 44 of Utah Power & Light Company. Schedule No. 37 establishes standard prices for purchases of power from Utah-located Qualifying Facilities (“QFs”) with a design capacity of 1,000 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 Abut for@ the generation provided by the QFs. These avoided costs have been used in other dockets to evaluate contracts and resource acquisitions.

On September 12, 2003, the Company filed updated avoided cost rates for consistency with its IRP 2003, acknowledged by Commission order on May 30, 2003. On November 21, 2003, the Commission ordered the Company to refile, by January 16, 2004, the avoided cost rates using the method approved in Docket No. 94-2035-03. Due to resource constraints, the Company requested a file date extension to January 30, 2004, which the Commission granted. The Company now requests, with an effective date of March 1, 2004, date and price changes to Schedule No. 37, using the Commission requested method.

Also on January 30, 2004, the Utah Energy Office, Wind Tower Composites LLC, Utah Clean Energy

Alliance, Wasatch Clean Air Coalition, Renewable Energy Development Corporation, and Tasco Engineering ("Petitioners") petitioned to intervene in this matter and requested a tariff revision. Petitioners request an increase in the maximum design capacity from one megawatt (1,000 kilowatts) to three or five megawatts for wind-powered QFs. Petitioners were granted leave to intervene on February 3, 2004.

Leave to intervene was additionally requested by and granted to United States Executive Agencies ("USEA"), US Magnesium, LLC, and Desert Power, L.P.

Additionally, on May 20, 2004, we heard arguments for and accepted a stipulation regarding indicative prices for Qualifying Facilities greater than one megawatt in Docket No. 03-035-14. Some of the stipulated adjustments accepted in that proceeding apply to this proceeding and therefore, fairness and consistency dictate that we take administrative note of that proceeding in rendering our decision here.

On January 30, 2004, the Commission requested that the Utah Division of Public Utilities ("Division") investigate and review the proposed changes. Throughout the process of review, parties requested and were granted extensions for review due to competing resource requirements mainly related to the Currant Creek Certificate of Convenience and Necessity proceeding and the increased scope of review needed for the Petitioners' request. On April 13, 2004, the Division filed its review and recommendations. The Division recommends adoption of the proposed rates with minor changes, and recommends increasing the QF size limit to five megawatts for all QFs on an experimental basis and with a cap of 25 megawatts at which time Schedule No. 37 rates would require an update.

On April 9, 2004, the Utah Committee of Consumer Services ("Committee") filed its recommendations on the proposed rate request and tariff revision. The Committee recommends adoption of the rates subject to several changes and supports an increase in the one megawatt size limit to three megawatts for wind-powered QFs. On April 15, 2004, USEA filed comments in support of the Division's proposal to increase the QF size limit to five megawatts on an experimental basis with no restriction on fuel type. The Company filed additional comments on February 12, 2004 and April 22, 2004. In the first set of comments it opposed the Petitioners request for size limit change and requested a hearing to set a schedule on the matter and in the second set of comments it responded to the Division and Committee recommendations. Comments responsive to the Company's second set of comments were filed by the Committee and the Petitioners.

DISCUSSION, FINDINGS AND CONCLUSIONS

The Company=s filing of January 30th provides a calculation of avoided costs consistent with the method approved in Docket No. 94-2035-03. This method differentiates between periods of resource sufficiency and deficiency. Resource deficiency is marked by resource deficit in annual energy, summer and winter peak. The Company represents that this occurs in July 2007. From 2004 to June 2007, the system has sufficient energy and winter capacity but is deficit in summer. Thus, avoided cost from 2004 through June 2007 is calculated as the cost avoided by a 10 MW zero cost resource plus avoided summer capacity cost. The avoided summer capacity cost is based on the fixed cost plus variable operation and maintenance cost of a Simple Cycle Combustion Turbine ("SCCT"). The theoretical costs of a Combined Cycle Combustion Turbine ("CCCT") with duct-firing are used beginning in July 2007 and for the remaining years of the calculation. For comparison purposes, the costs are then levelized assuming a given capacity factor over a 20-year contract starting in 2004. The levelized price, assuming an 85 percent capacity factor, is $46.57 per megawatt hour. This is 10 percent higher than the current levelized rate of $42.26 per megawatt hour for the 2001 to 2020 period.

Any estimation of avoided costs requires assumptions regarding the Company=s future loads and resources, the least-cost plant type, cost and characteristics, inflation and discount rates, natural gas prices, and wholesale electric prices. The Division and Committee review these assumptions and inputs to insure that 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 load and resource balance in this filing differs from the Company's IRP 2003 projections as a result of additions or revisions to long-term purchase contracts including Pinnacle West, Grant County, P4 Production, Powerex, Combine Hills, two Arizona Public Service Company purchases and the addition of the Currant Creek power plant. The load forecast also differs from IRP 2003 projections; the filed load and resource balance is based on a new load forecast completed by the Company in March, 2003. The new load and resource balance shows a summer peak deficit in all years, and a surplus in winter peak and annual energy until July 2007. The Division explains that compared to IRP 2003, there are differences in the magnitude of surplus or deficit in a given year but that the timing of deficit, which dictates the periods of resource sufficiency and deficiency, is consistent with the IRP 2003 projections.

Avoidable Resource Type, Cost, and Characteristics

During the years 2004-2006, PacifiCorp proposes to make a capacity payment based on three summer months of deficit. Based on its review of the load and resource balance for all 12 months, the Committee says that payments based on six months of capacity deficit is warranted. The Company agrees that the three-month capacity purchase could be viewed as conservative but that five, rather than six months, could be prudent. In Docket No. 03-035-14, some parties argue that the West Valley lease can be terminated in 2006 and 2007 and therefore can be deferred. West Valley lease payments are made in all twelve months and therefore, it is argued, its costs are avoidable in all twelve months. Parties in Docket No. 03-035-14 stipulated to five months of capacity payment in 2004 and 2005 and twelve months in 2006 and 2007.

The Committee also recommends that the summer season be defined as the four summer months of June to September rather than the six months of May to October. The Company agrees with this recommendation because its expected costs are clearly higher in the four summer months than the other eight months of the year.

We accept the change in definition of summer months to June-September, as it will provide a better price signal of the cost of summer power. For accuracy, fairness and consistency with Docket No. 03-035-14, we conclude that the calculation of capacity payments should reflect five rather than three months in 2004 and 2005 and twelve months in 2006 and 2007. These two changes increase the levelized cost per megawatt hour, assuming an 85 percent capacity factor, to $47.62.

The estimated capital cost and fixed and variable O&M costs of an SCCT, without transmission cost, is the proxy resource used to value capacity payments from 2004 to June 2007. A CCCT with duct-firing capability is the proxy resource used to value capacity and energy payments from July 2007 through the remaining 20 years. Neither the Division nor Committee comment on whether a CCCT with duct-firing capability is consistent with the IRP 2003 avoidable resource in 2007. However, we recall that it is consistent with the plant PacifiCorp identified as its 2007 "Next Best Alternative" in Docket No. 03-035-03.

The SCCT capital costs, including transmission cost, are also used in the CCCT cost calculation to differentiate capacity price from energy price. We take administrative note that parties in Docket No. 03-035-14 stipulate to converting only half of the CCCT capital cost in excess of the SCCT capital cost to energy for final capacity and energy price determination. For consistency and fairness, we accept this change for Schedule No. 37 prices. This change has no effect on levelized cost per megawatt hour over the 20-year period, assuming an 85 percent capacity factor, but raises capacity prices and reduces energy prices.

The Committee reviewed PacifiCorp's capital cost assumptions and concludes that the estimates of $595/kW and $532/kW for an SCCT with and without transmission cost respectively, and $726/kW for a CCCT unit including transmission cost and duct-firing capability, are consistent with IRP 2003 and Currant Creek cost estimates.

Both the Division and Committee indicate that the payment factors, a factor used to annualize the capital cost noted above, may require correction. The Division notes that PacifiCorp incorrectly uses a 7.5 percent rather than 7.52 percent discount rate and although the difference is immaterial, it recommends the discount rate be corrected for consistency of discount rate application. We agree with this correction. Correcting the discount rate changes the payment factors from 9.7 percent and 8.7 percent to 9.6882 percent and 8.7066 percent for SCCT and CCCT capital costs respectively. With these corrections, the new Schedule No. 37 levelized cost per megawatt hour at an 85 percent capacity factor is $47.63.

The Committee notes that the payment factors are different than IRP 2003 values but that the difference is insignificant. However, the Committee notes a substantial change from the payment factors used in current Schedule No. 37 rates which they believe requires additional explanation. We note that there has been a substantial change in the assumed life of an SCCT generating plant since the existing Schedule No. 37 rates were approved. The SCCT payment factor in current Schedule No. 37 rates is based on a 30-year assumed life. Since then, we have approved a depreciation stipulation that set the life of the Gadsby Peakers, aero-type SCCTs, to 25 years, and this has become the equipment life assumed in IRP 2003 for all SCCT plant types. This one change would account for a notable change in the SCCT payment factor.

In its review of the fixed and variable operation and maintenance ("O&M") cost assumptions for a CCCT with duct-firing, the Division notes that the assumptions do not comport with the estimates of Currant Creek. The Division recommends using the Currant Creek estimates as they represent the best available estimates for O&M costs and therefore a better measure of avoided cost. The Company concurs with this recommendation. We agree and accept the Division's recommended change of the fixed cost O&M assumption from $10.07 per kilowatt-year to $9.72 per kilowatt-year and the variable cost O&M assumption in the combined cycle mode from $2.47 per megawatt-hour to $3.19 per megawatt-hour. The Division and Committee both note and the Company acknowledges a spreadsheet error wherein the fixed and variable O&M costs of a CCCT are mistakenly used for SCCT O&M costs. Correcting this error and using Currant Creek O&M cost estimates raises the levelized cost per megawatt hour, assuming an 85 percent capacity factor, to $48.38.

The Committee's review of heat rates indicates the assumed rates are reasonable in comparison to IRP 2003 and Currant Creek. However, the Division notes that the heat rates, 10,467 and 7,623 BTU's per kilowatt hour respectively for SCCT and CCCT with duct firing, do not exactly match Currant Creek estimates of 10,500 and 7,626 BTU's per kilowatt hour respectively, and suggests the heat rates for Currant Creek be used. The Company concurs with this change. We accept the Division's recommended heat rates because they are consistent with the best available information for computing avoided cost. This change combined with the previous changes has no effect on levelized cost per megawatt hour at an 85 percent capacity factor which remains $48.38.

Natural Gas Prices

The Division and Committee both review the Company's forecast of natural gas prices. The Company's forecast is a combination of the Company's own projections of natural gas prices to January 2007 and long-term price projections from the forecasting firm of PIRA Energy Group to 2023. The two sources are blended in years 2007 to 2010. The delivered gas prices begin in 2004 at $5.07 per million BTU. These are nominal prices that decline until 2010 and then escalate through to 2023. The average annual nominal escalation for the twenty year period shown in the tariff is one half of one percent per year.

The Division and Committee each compare the Company's price stream to one other forecast. The Committee uses a January 2004 forecast from the U.S. Department of Energy, Energy Information Administration ("EIA") which provides an average annual nominal escalation for the 20-year period of 3.4 percent per year. Additionally, the Committee compared it to NYMEX gas futures prices for the Henry Hub for years in which data is available. The Division compares the Company's forecast to an EIA forecast of natural gas prices to electric utilities that has an average annual escalation for the 20-year period of 0.5 percent per year and concludes from its review that the Company's forecast is reasonable.

The Committee concludes from its review that the Company's gas price forecast is low and recommends an alternative stream of natural gas prices that lie above the Company's forecast and below either the NYMEX prices or the EIA forecast, depending on year. The projection is based on the NYMEX prices at Henry Hub with a $0.40 per million BTU adjustment to account for the difference in natural gas price between Henry Hub and Opal, Wyoming. The delivered natural gas price begins in 2004 at $5.57 per million BTU and escalates one percent on an average annual basis through the 20-year period. The Committee recommends adoption of its stream of gas prices as more representative of likely natural gas prices and therefore better estimates of avoided cost. In the alternative, the Committee recommends tying the Schedule No. 37 payment calculation to an indexed fuel price at the time the QF power is delivered to the Company. The Company opposes both recommendations. It argues that its forecast is more reflective of Utah gas prices and that the Committee's stream of prices understates the gas price differential between Henry Hub prices and Utah prices. Further, the Company recommends addressing the indexing approach to QF pricing in Docket No. 03-035-14 where it will receive formal debate.

In responsive comments, the Committee concurs that its initial fixed gas price proposal understates the differential between Henry Hub and Utah gas prices. It increases this differential and recommends the adoption of its new stream of gas prices. These prices begin in 2004 at $4.89 per million BTU and have an average annual nominal escalation of 1.1 percent per year over the 20-year period. The Committee also notes that the Division compared PacifiCorp's nominal gas price stream to an EIA real price stream and surmises that had the Division compared the nominal forecasts against each other that their conclusion about the reasonableness of PacifiCorp's gas price forecast would likely be different.

Clearly, natural gas prices are an important input to Schedule No. 37 rates. However, natural gas prices in the future are unknown and forecasting these prices, with any level of confidence, difficult. Although the use of a natural gas price index to set price for the QF at the time of power delivery would remove forecasting error, it would also add a degree of complexity and uncertainty to this schedule that may be difficult or burdensome to implement for such small projects. We do not have adequate examination of the applicability to small projects of the indexing option included in the stipulation of Docket No. 03-035-14. Further, it is our understanding that federal law or regulation leaves to the QF the choice of a variable price for its power and we have no evidence in this case that this is a preference of small QFs in Utah. Therefore, at this time, we do not adopt an indexing approach for Schedule No. 37. We note that in Docket No. 03-035-14, the parties stipulate to, and none oppose, a natural gas price projection that is an average of the Company's and Committee's recommendations. The delivered starting price in 2004 for this gas price projection is

$4.98 per million BTU and the average annual nominal escalation rate is 0.8 percent per year from 2004 through 2023. For fairness and consistency with the indicative rates approved in Docket No. 03-035-14, we accept these natural gas prices as reasonable assumptions for calculating avoided cost for Schedule No. 37 rates in this case.

The cumulative effect of the Company’s application and the adjustments accepted in this order provides a levelized cost per megawatt hour over the 20- year period assuming an 85 percent capacity factor of $48.62. This is 15 percent higher than current rates and 4 percent higher than the rates proposed by PacifiCorp in its initial filing.

Schedule No. 37 Size Restriction

Petitioners request that the one megawatt design capacity limit for Schedule No. 37 eligibility be increased to three or five megawatts for wind resources. Petitioners present three arguments in support of their request. First, the current tariff discriminates against wind-powered resources because it does not take into account the low capacity factor of wind turbines. Wind resources are known to operate at about a 30 percent capacity factor and therefore a three megawatt wind turbine yields the energy of a one megawatt fossil-fuel based QF operating at a 90 percent capacity factor. Second, IRP Standards and Guidelines support consistent and comparable treatment of resources taking into account unique resource characteristics. Third, both physical and economic efficiencies can be obtained from turbines larger than the one megawatt design limit. The typical size for a wind turbine on land is 1.8 megawatts. Increasing the design capacity limit will encourage the use of more efficient wind turbines. Finally, Petitioners encourage the Commission to adopt a five megawatt design limit to allow for technological innovation as efficiency improvements continue to be made.

The Division supports an increase in the capacity limit to five megawatts on an experimental basis for all QF’s eligible for Schedule No. 37 rates. The Division recommends a 25 megawatt cumulative cap be placed on this tariff. After 25 megawatts, the Division recommends an update of Schedule No. 37 rates for consistency with the method used to develop the rates which is currently based on 10 megawatts of QF capacity. The experiment is to run for two years at the end of which the Division will report to the Commission.

The Committee recommends that if the Commission approves an increase in the design capacity eligible for Schedule No. 37 rates, that the increase be limited to three megawatts for wind resources. This is because Schedule No. 37 is designed for administrative simplicity for small projects; a larger project should have the financial means to negotiate a contract. Moreover, the output of three megawatts of wind is comparable to one megawatt of a fossil-fueled facility and therefore a higher limit would confer an unfair advantage to wind resources. The Committee alternatively recommends the Commission defer a decision in this matter until issues associated with renewable energy credits are fully examined in Docket No. 03-035-14.

USEA supports the Division's proposal. It has a QF project under development which will be one megawatt initially and may increase to three megawatts in the future. The QF will use renewable energy, methane gas from a landfill, to generate electric power, and thus will qualify as a small power production facility as defined in Schedule No. 37. USEA proposes that Schedule No. 37 include renewable energy credits and supports the Committee's recommendation to defer making a decision regarding a change to Schedule No. 37 until the renewable energy credit issue is resolved in Docket No. 03-035-14.

The Company supports the Division's proposal to raise the QF design capacity limit to five megawatts without restriction on fuel type, with a 25 megawatt cap, and on an experimental basis. To avoid overpayment to low-capacity resources, the Company recommends eliminating the capacity and energy price option from the filed tariff to remove the possibility of overpayment. All QFs, regardless of fuel type, would be entitled only to the time-differentiated pricing provided in the tariff.

We are persuaded that an increase in the size limit to three megawatts for an intermittent wind resource is reasonable; it comports with the comparable output of a fossil-fuel QF of one megawatt and is therefore fair. It also encourages use of more efficient technology that promotes the public interest. We accept the notion of a cap. Current rates are based on a 10 megawatt decrement during the period of sufficiency and therefore 10 megawatts serves as a reasonable cap. When the cap is reached, a new cap will be considered and new rates calculated. To accommodate other renewable projects that may exceed the one megawatt limit, like USEA's project, we approve this new size limit for all QFs that are defined as "small power production facilities" in Schedule No. 37 and in section 54-2-1 (20) (a) of the Utah Code. The increase will again encourage efficient and clean power production and over-subscription from raising the design limit from one to three megawatts is checked by implementation of the overall 10 megawatt cap. We concur with the Company that the capacity and energy pricing option systematically overpays low capacity resources and should be eliminated as an option for wind resources going forward. Indeed, our own calculation shows that under the capacity and energy payment option, a three megawatt wind project at a 30 percent capacity factor will produce the equivalent amount of energy as a one megawatt cogeneration project operating at a 90 percent capacity factor but that the wind-resource owner would be paid 52 percent more for the power. This may be viewed as unfair by cogeneration QFs. All QFs other than wind resources will continue to have the two pricing options. We refrain from the complete elimination of the capacity and energy price option at this time because we do not have adequate examination regarding the issue as it applies to resources with a higher capacity factor.

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 No. 44 are approved with the adjustments noted herein. Specifically, these adjustments are: 1) summer is defined as the four months of June through September; 2) capacity payments during years of sufficiency shall be based on five months in 2004 and 2005 and twelve months in 2006 and 2007; 3) the Division's recommended SCCT and CCCT heat rates and payment factors, CCCT fixed and variable costs and SCCT fixed and variable cost spreadsheet correction shall be used in calculating Schedule No. 37 rates; 4) half of the CCCT capital cost in excess of the SCCT capital cost shall be converted to energy for final capacity and energy price determination; 5) the gas price estimate used assumed for indicative prices in Docket No. 03-035-14 shall be used in calculating Schedule No. 37 rates; 6) design capacity limit for small power production facilities is increased from 1,000 kilowatts to 3,000 kilowatts; 7) wind resources shall be limited to the seasonally and time differentiated pricing option; 8) a cap of 10 megawatts is placed on payments made from the Schedule No. 37 rates approved in this order.

The Company shall submit to the Commission the appropriate tariff sheets for Electric Service Schedule No. 37 that reflect the decisions made in this order as shown in the Attachment to this order. The effective date of the changes shall be the date of this order.

DATED at Salt Lake City, Utah, this 1st day of June 2004.

/s/ Ric Campbell, Chairman

/s/ Constance B. White, Commissioner

/s/ Ted Boyer, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary

G#38636

Docket No. 03-035-T10
Tariff Utah Schedule 37
Prices

Year	Capacity Price $/kW-mo	Energy Only Price ¢/kWh	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh	Total Price @ 0.85 Capacity Factor ¢/kWh
2004	2.59	3.12	3.84	3.87	3.11	3.14	3.54
2005	2.66	4.19	4.21	6.39	3.46	5.64	4.61
2006	6.53	3.96	5.20	7.04	3.35	5.19	5.02
2007	7.23	3.51	5.41	5.85	3.40	3.74	4.68
2008	7.95	3.24	5.48	5.48	3.24	3.24	4.52
2009	8.15	3.23	5.54	5.54	3.23	3.23	4.55
2010	8.35	3.16	5.52	5.52	3.16	3.16	4.51
2011	8.56	3.22	5.64	5.64	3.22	3.22	4.60
2012	8.77	3.34	5.82	5.82	3.34	3.34	4.75
2013	8.99	3.41	5.95	5.95	3.41	3.41	4.86

2014	9.22	3.48	6.09	6.09	3.48	3.48	4.97
2015	9.45	3.58	6.25	6.25	3.58	3.58	5.10
2016	9.68	3.69	6.43	6.43	3.69	3.69	5.25
2017	9.93	3.80	6.61	6.61	3.80	3.80	5.40
2018	10.17	3.91	6.79	6.79	3.91	3.91	5.55
2019	10.43	4.03	6.98	6.98	4.03	4.03	5.71
2020	10.69	4.16	7.18	7.18	4.16	4.16	5.88
2021	10.96	4.29	7.38	7.38	4.29	4.29	6.05
2022	11.23	4.42	7.59	7.59	4.42	4.42	6.23
2023	11.51	4.55	7.80	7.80	4.55	4.55	6.40
	20 Year Levelized Prices (Nominal) @		7.52%	Discount Rate			
	7.73	3.62	5.68	6.05	3.50	3.85	4.86
$/MWH		36.15	56.79	60.46	34.96	38.54	48.62