State of Utah

DEPARTMENT OF COMMERCE
Committee of Consumer Services

CCS EXHIBIT 2.2

To: The Public Service Commission of Utah

From: The Committee of Consumer Services
Roger Ball, Director
Dan Gimble, Chief of Technical Staff

Phil Hayet, Consultant
Kelly Francone, Utility Analyst

Copies To: PacifiCorp
D Douglas Larson, Vice President of Regulation
The Department of Commerce
Klare Bachman, Executive Director
The Division of Public Utilities
Irene Rees, Director
Judith Johnson, Energy Section Manager
William Powell, Technical Consultant

Date: 9 April 2004

Subject: Recommendations of the Committee of Consumer Services Regarding Schedule 37: Avoided Cost Purchases from Qualifying Facilities up to 1 MW No. 03-035-T10

1 Background

PacifiCorp's current Schedule 37 Tariff for Qualifying Facilities (QFs) up to 1 MW in size was originally approved on 15 January 2002 in Docket 01-2035-01. On 30 May 2003, the Commission issued an order acknowledging PacifiCorp's 2003 Integrated Resource Plan (IRP). This acknowledgement led to the need for PacifiCorp to update its avoided cost rates based on IRP results. PacifiCorp filed updated avoided cost rates on 12 September 2003 under Docket No. 03-035-T10. Although PacifiCorp's proposed changes in its 12 September 2003 filing were consistent with the data assumptions in the latest IRP, the Committee was concerned that a number of key assumptions (eg load forecasts, market price forecasts) were outdated. For example, at the time it filed its Schedule 37 avoided costs, PacifiCorp was in the process of revising certain data assumptions for use in the November 2003 IRP Update and in the November 2003 Currant Creek Certificate of Convenience and Necessity (CCN) filing.

In its 4 November 2003 memo to the Commission on PacifiCorp's 12 September filing, the Committee recommended that the Commission either take no action until the underlying data assumptions could be updated to reflect the most current information available, or accept the avoided costs on an interim basis and order PacifiCorp to revise them when updated information became available.

On 23 November 2003, the Commission issued an Order in Docket No. 03-035-T10, in which it based its decision on comments from the Division of Public Utilities' (Division) and the Committee, and on another issue regarding the methodology. In that Order, the Commission required PacifiCorp to refile its Schedule 37 avoided cost rates to "better reflect changed circumstances"[1], and alter the methodology. The Commission determined that PacifiCorp needed to alter its avoided cost methodology due to the distinct change in the Company's load/resource balance from the previous Schedule 37 filing in 2002.

In recommending a change in the avoided cost methodology, the Commission referenced previous orders such as its 7 July 1995 decision for Docket No. 94-2035-03. On 30 January 2004, PacifiCorp refiled its Schedule 37 avoided costs in compliance with the Commission's 23 November 2003 order. This memo provides the Committee's recommendations on this most recent filing.

2 Recommendation

While the Committee is generally satisfied that PacifiCorp's avoided cost methodology is reasonable for setting Schedule 37 avoided cost rates, the Committee has some specific concerns relating to both the methodology and data assumptions. In addressing these concerns, the Committee recommends that the Commission adopt the following changes.

2.1 The Committee recommends the Commission limit the definition of the summer period to June through September. PacifiCorp has defined this seasonal period as May through October, which distorts the true summer and winter periods, as well as the corresponding avoided costs.

2.2 The Committee recommends the Commission expand the minimum number of months in which the avoided cost capacity payments should be made from three months to six months. The three months recommended by PacifiCorp does not comport with the number of months it is capacity deficient and thus requires additional capacity resources.

2.3 In determining the variable and fixed O&M costs assumed for a Simple Cycle Combustion Turbine (SCCT), PacifiCorp made an error, which the Committee has corrected, and recommends the adoption of.

2.4 The Committee recommends that the Commission adopt a more accurate averaging calculation for annual average avoided costs. PacifiCorp's methodology distorts the average, which impacts the avoided costs.

2.5 Due to the volatility of natural gas prices and the subsequent impact on the avoided costs, the Committee provides two options relating to natural gas prices: 1) if the

[1] Page 5 of the Commission Order in Docket No. 03-035-T10, issued 23 November 2003.

Commission prefers a fixed price forecast, we recommend the Commission adopt the Committee's alternative gas price forecast that is based on PacifiCorp's forecast and those provided by Nymex and the Energy Information Administration (EIA); or 2), if the Commission prefers relying on actual gas prices to reflect more accurate fuel costs, the Committee recommends the Commission tie the cost to the index fuel price and set rates at the time the power is delivered.

Finally, regarding the proposal regarding wind-powered QFs, the Committee recommends increasing the capacity limit to 3 MWs for wind-based QFs selling power under Schedule 37.

3 Analysis

The Committee's objective in its examination of PacifiCorp's filing is to meet the standards set forth by the Public Utility Regulatory Policies Act, which ultimately are ratepayer neutrality and equitable rates for eligible power producers to create a market in which QFs can thrive. In its 21 November Order the Commission adopted the Committee recommendation to do nothing until more accurate data assumptions became available. The Committee now comments on the following issues:

- Avoided Cost Methodology;
- Avoided Cost Data Assumptions; and
- Increase in the Capacity Limit for Wind Power QFs

3.1 Avoided Cost Methodology

Based on our review of PacifiCorp's proposed avoided cost methodology, the Committee is satisfied that if the Commission adopts specific adjustments proposed by the Committee, the methodology for developing avoided costs for QFs of up to 1 MW in size is reasonable.

3.1.1 Commission Precedent Concerning the Avoided Cost Methodology

Based on a review of previous Commission Orders dating back to1994, it appears the Commission originally accepted PacifiCorp's recommendations for calculating Schedule 37 avoided costs. The Commission's 7 July 1995 Order in Docket No. 94-2035-03 established that the appropriate methodology of computing avoided costs should be to use a combined differential revenue requirement and proxy unit methodology. In that order, the Commission stated the following:

> *The Company's proposed methodology for computing avoided costs is a combined differential revenue requirement and proxy methodology. During the period from 1994 through 1999, the avoided costs are based on the marginal energy production costs of operating the Company's existing system, plus the cost of purchasing summer capacity. During the period 2000 and beyond, the avoided costs are based on the fixed and variable costs of a combined cycle combustion turbine (CCCT).*

However, the Commission never mentioned under what conditions the differential revenue requirement versus the proxy methodology should be used, only that for the years 1994 – 1999 the differential revenue requirement should be used, and after that period the proxy methodology should be used. In a subsequent Commission Order issued 23 February 2001 in Docket 97-2035-02, the Commission clarified that *"When capacity and energy are deficit, the Commission has relied on the use of the proxy resource to estimate avoided costs for Qualifying Facilities."* In a deficit situation, PacifiCorp should use the proxy plant approach, and in a surplus situation, it should use the differential revenue requirement approach.

In its 21 November 2003 Order, the Commission further stated,

> *Now, however, PacifiCorp states that it has adequate winter peak resource and annual energy until 2007. This time frame would allow, and indeed, according to the Company's Current Creek certificate application does allow, the Company time to construct a proxy CCCT. A CCCT is also shown by the Company's IRP 2003 to be the least cost plant in 2007. The period of winter peak and energy sufficiency in the current filing, based on the Commission's Order in Docket No. 94-2035-03, would dictate a differential revenue requirement approach until 2007. In Docket No. 80-999-06, the Commission stated that "Avoided costs will change as economic and financial circumstances affecting them do" (page 8). Therefore, we direct the Company to refile its Schedule No. 37 rates to better reflect changed circumstances.*

For purposes of computing Schedule 37 avoided cost rates, the Committee is satisfied with the Commission's 21 November Order in this docket in which it required PacifiCorp to refile its avoided costs using a combined differential revenue requirement/proxy approach.

3.1.2 Significance of Schedule 38 Filing

It is important to note that PacifiCorp has also filed for approval of its Schedule 38 avoided cost methodology for QFs greater than 1 MW in size. PacifiCorp proposes that the Commission adopt the same avoided cost methodology for both Schedules 37 and 38.

When the time comes to hear the Schedule 38 case, the Commission should not necessarily feel compelled to adopt the same methodology for Schedule 38 avoided costs that it determines reasonable for Schedule 37 avoided costs. For purposes of Schedule 37 avoided cost rates, the Committee has no objection to the use of the combined differential revenue requirement/proxy methodology. However, in determining avoided costs for larger QFs, the Committee believes that the combined methodology is inappropriate. This issue will be discussed in the Committee's Schedule 38 testimony.

3.1.3 Adjustments to PacifiCorp's Methodology

The Committee proposes four specific adjustments to the Company's avoided cost methodology. These adjustments are identified and discussed below.

3.1.3.1 Readjustment of Summer and Winter Periods

PacifiCorp defines its summer season to include the six-month period between May and October, and the winter season to include the remaining six months in the year, November through April. However, there doesn't appear to be any support for that seasonal definition when considering PacifiCorp's loads and costs. The summer period is usually the highest load period, and has the highest average costs in the year. By including both May and October in the summer period, PacifiCorp has included shoulder months that have more in common with the winter period than they have with the summer period. The impact on the avoided cost calculation is that the summer period avoided costs are lower than they should be, and the winter period avoided costs are higher than they should be.

Figure 1 shows the peak loads that PacifiCorp assumes for each month between 2004 and 2008. Figure 2 shows the monthly average system cost as computed using PacifiCorp's GRID model, which was used for the computation of the avoided costs. Each of these graphs show that the months of May and October are dissimilar compared to the other summer months and are more aligned with the winter months. Thus, in the calculation of summer avoided costs only the months of June through September should be included, while the remaining months should be included in the winter period.

Figure 1

PacifiCorp Monthly Peak Load Data

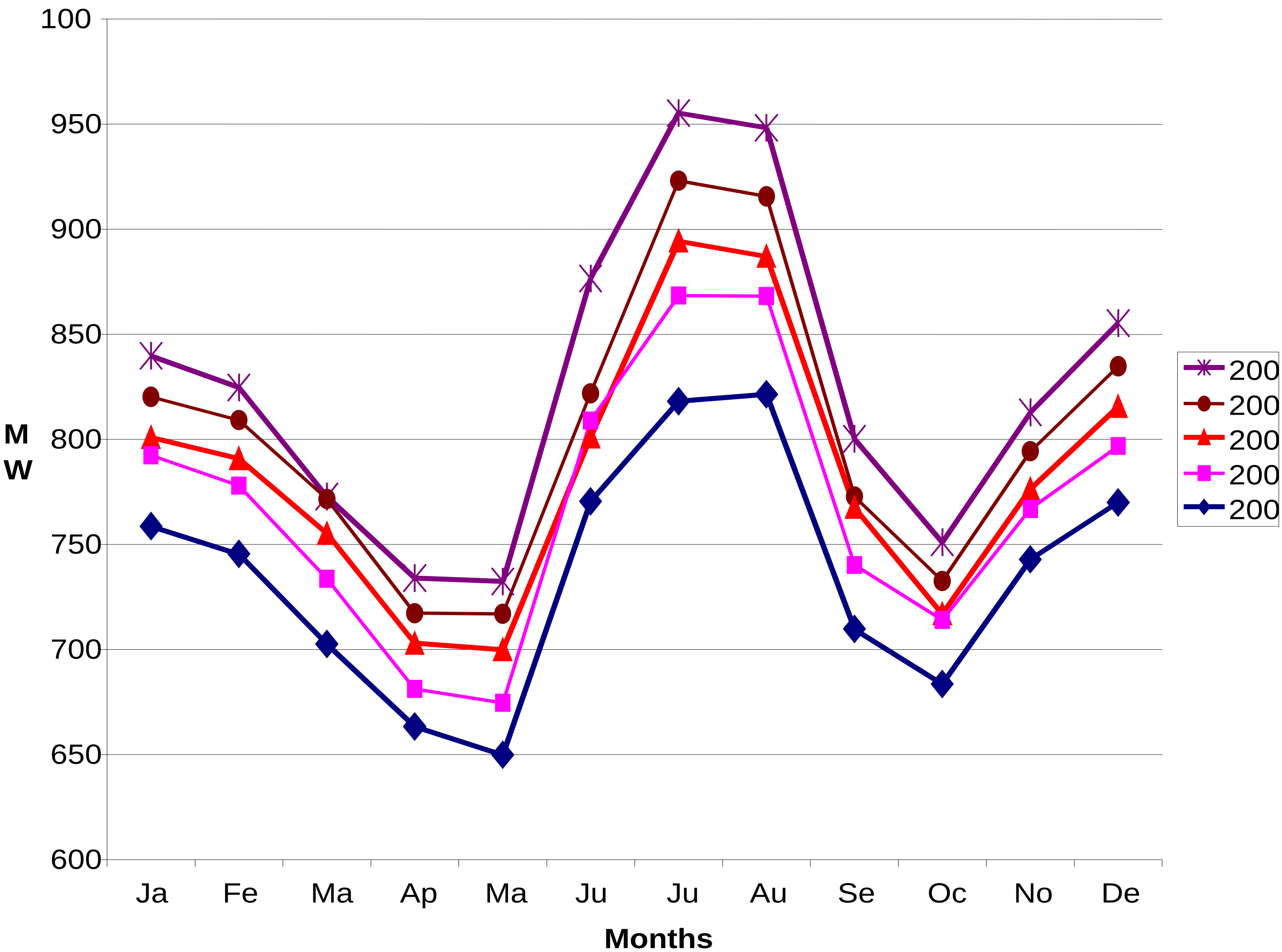
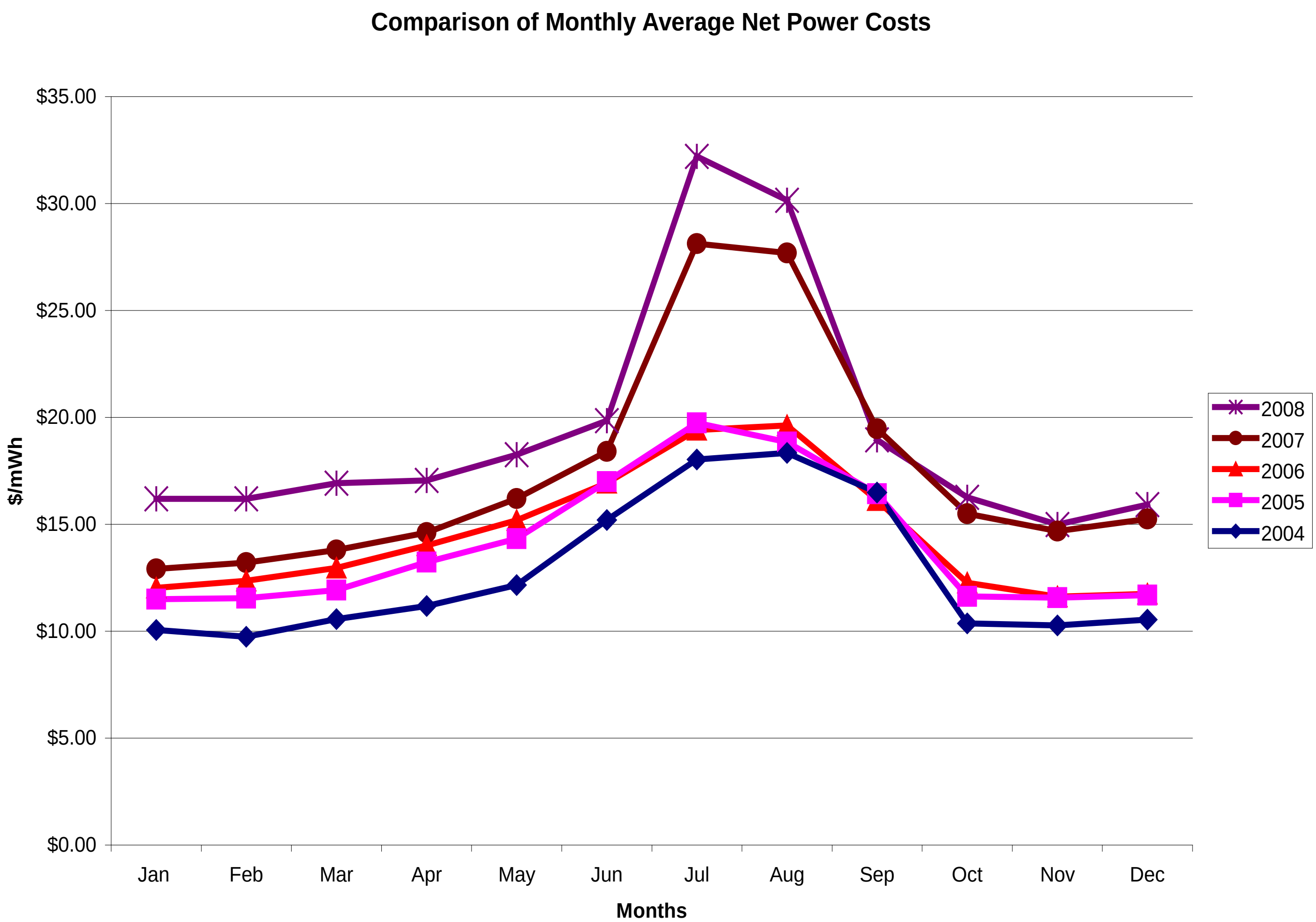


Figure 2

PacifiCorp Monthly Average Net Power Costs



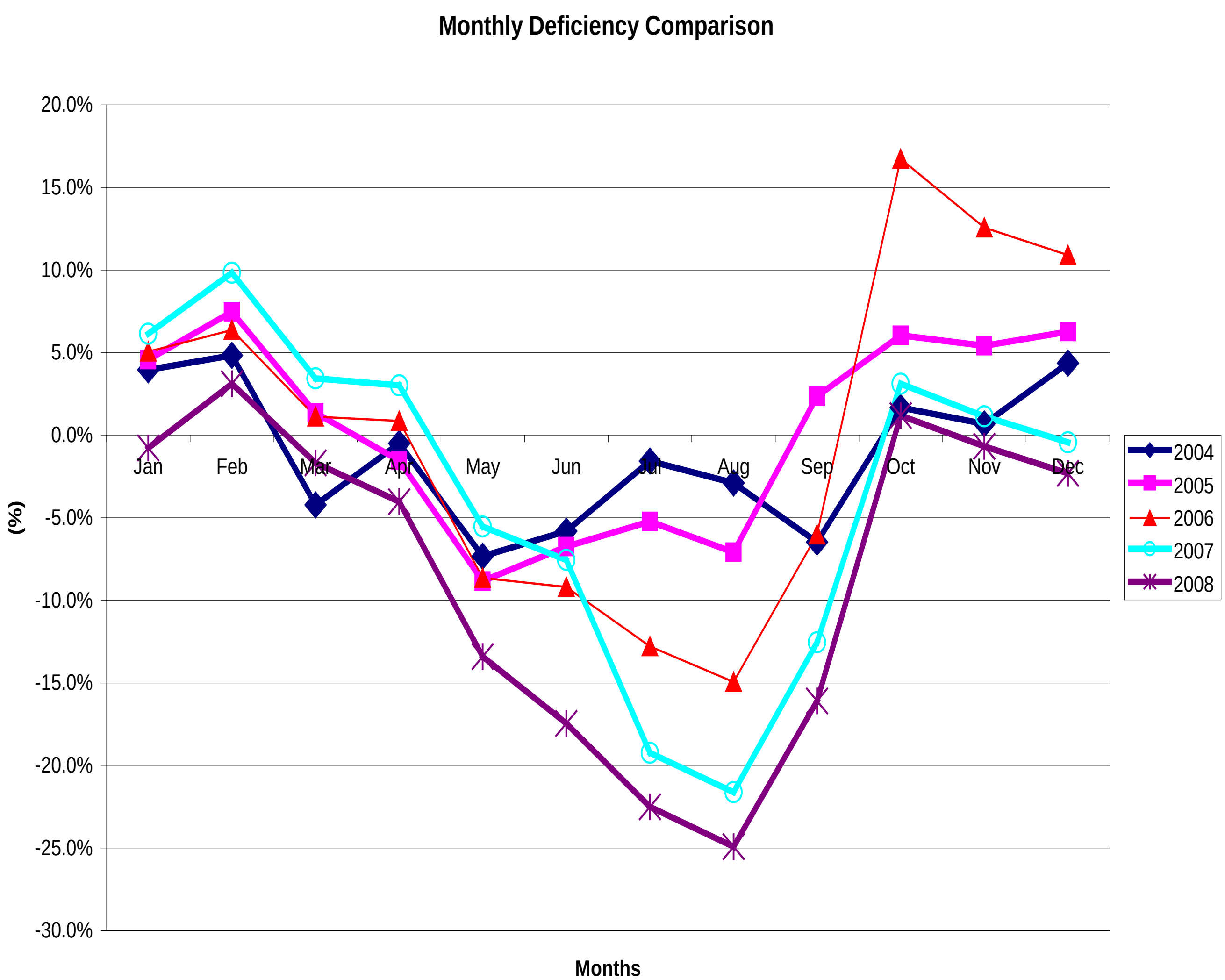
3.1.3.2 Readjustment of Avoided Cost Capacity Payment During Sufficiency Period

As previously discussed, the Commission has established the precedent that when the Company is in a peak-period capacity deficit position, but in an annual energy sufficiency position, the Company should use the differential revenue requirement methodology for calculating avoided costs, and when the Company is in a resource deficiency position with regard to both capacity and energy, the Company should rely on the proxy methodology for computing avoided costs. While the Committee finds this approach to be reasonable for purposes of calculating the Schedule 37 avoided costs, it is concerned with the fact that during the sufficiency period, PacifiCorp has decided only to make a capacity payment to the QFs during the three summer months.[2]

In examining the load and resource balance for all 12 months of the year, there are at least three additional months where the Company has a capacity deficiency. The following graph, Figure 3, compares the capacity deficiency for each month of each year between 2004 and 2008. Figure 3 illustrates that during the period of 2004 – 2006, the average number of months per year of a deficit condition is six. The Committee therefore recommends that the Commission require avoided cost capacity payments be made for at least six months of the year.

[2] In this situation, PacifiCorp assumes there are only 3 months in the summer period, which includes June, July and August.

Figure 3
PacifiCorp Monthly Deficiency



3.1.3.3 Variable and Fixed O&M Correction for SCCT Unit

Table 8 of PacifiCorp's avoided cost calculations has an error that requires correction. The Table incorrectly references the variable and fixed O&M for a CCCT unit as the O&M costs for a SCCT unit. PacifiCorp acknowledged this error in a data response to the Division (DR DPU 1.2). The Committee has corrected this error in its revision of PacifiCorp's avoided cost calculation.

3.1.3.4 Incorrect Average Calculation

There is a minor problem in PacifiCorp's methodology for computing an average annual energy cost on its Tariff Page spreadsheet used in the calculation of avoided energy costs. Instead of summing up 12 monthly values and taking the average of those monthly values to get the annual average value, PacifiCorp computes average values for a subset of summer and winter months. The Company then averages the winter and summer average values to get an annual average. This approach leads to a slightly different result than what is calculated by averaging all 12 monthly values together. The Committee has corrected this in its calculation.

3.2 Avoided Cost Data Assumptions

In comparing the previous Schedule No. 37 avoided costs to those proposed in the current filing, the Committee has carefully evaluated the underlying data assumptions that PacifiCorp relied upon and compared those assumptions to what was used in the previous filings. Data assumptions that were analyzed by the Committee include:

- capital costs;
- heat rates;
- levelization rates; and
- fuel costs.

3.2.1 Capital Costs

When comparing PacifiCorp's proposed data assumptions in the current docket to those relied on in the previous docket, PacifiCorp's assumed capital cost for a SCCT has increased from $505/kW to $595/kW, and from $603/kW to $726/kW for a CCCT.[3] These changes represent a 17.8% and 20.4% increase, respectively. While the latest capital cost estimates appear to be substantial increases, they are actually reasonable estimates of costs given the recent experience with PacifiCorp's 2003 IRP, as well as the Currant Creek CCN hearings. In the case of the SCCT unit, the $595/kW includes the cost of building the unit and interconnecting the unit with the system. Without interconnection costs, PacifiCorp's cost to build a SCCT is $532/kW, which is only a 5.4% increase over what was used for a SCCT unit in the last docket.

[4] $595/kW is assumed to include transmission interconnection costs. This is used when it is assumed that PacifiCorp will build a SCCT unit. However, prior to the time when a SCCT unit can be built, PacifiCorp assumes that summer purchases will be made at a cost similar to that of a SCCT, but in that situation no transmission interconnection costs will be required. Thus, the cost of a SCCT unit is assumed to be $532/kW.

In the case of a CCCT unit, PacifiCorp has proposed costs that are very similar to what it used in the Currant Creek proceedings for a Frame F type machine, including duct firing capability and interconnection costs. Without interconnection costs, the CCCT unit cost is $654/kW, which is an 8% increase over what was used for a CCCT unit in the last docket. The inclusion of interconnection costs in this docket is reasonable as it is a legitimate expense that can be either deferred or avoided through the purchase of capacity and energy from a QF.

It should also be noted that these costs are lower than the assumptions that PacifiCorp relied on in its initial 12 September 2003 filing. At that time, the Company assumed the cost of a CCCT unit to be $767/kW. In the Committee's comments filed on 4 November, the Committee expressed a concern that the $767/kW value appeared to be somewhat high, and at that time, it was the Committee's understanding that the $767/kW value did not include interconnection costs. Thus, the current estimate of $726/kW including duct firing and interconnection costs appears to be a reasonable estimate for the cost of a CCCT unit.

3.2.2 Heat Rates

Table 1 below compares heat rate assumptions that PacifiCorp has relied on in various Schedule 37 avoided cost filings.

(Begin Confidential)

(End Confidential)

The table shows that for the case of a SCCT unit, the assumptions used in the January 2004 filing represent the most efficient unit (the lower the heat rate, the more efficient the unit) compared to any of the previous filings and compared to what was used in the Currant Creek proceedings. The most important comparison is that of Currant Creek, which is very close to the heat rate used by PacifiCorp in its January 2004 filing. The difference between the heat rate values amounts to approximately 2%. Thus, PacifiCorp's SCCT heat rate assumption appears to be reasonable.

In the case of a CCCT unit, PacifiCorp has accounted for the fact that the unit has duct-firing capability. Duct firing allows a generating unit to produce additional MWs, but at a much lower efficiency compared to the rest of the CCCT unit. This results in a higher heat rate. In the past, PacifiCorp relied on a CCCT heat rate that was lower, or more efficient, because it did not consider that the plant would have duct-firing capability. Comparing the Currant Creek heat rate value (CCCT and duct firing) to what is now being used for PacifiCorp's latest avoided cost filing, results in a difference of only 4%. Thus, PacifiCorp's CCCT heat rate assumption appears to be reasonable.

3.2.3 Levelization Rates

Table 2 below compares levelization assumptions that PacifiCorp has relied on in various Schedule 37 avoided cost filings.

	Avoided Costs in effect since 2002	September 2003 Avoided Cost Filing	January 2004 Avoided Cost Filing
SCCT	8.59%	9.59%	9.70%
CCCT	8.37%	8.61%	8.70%

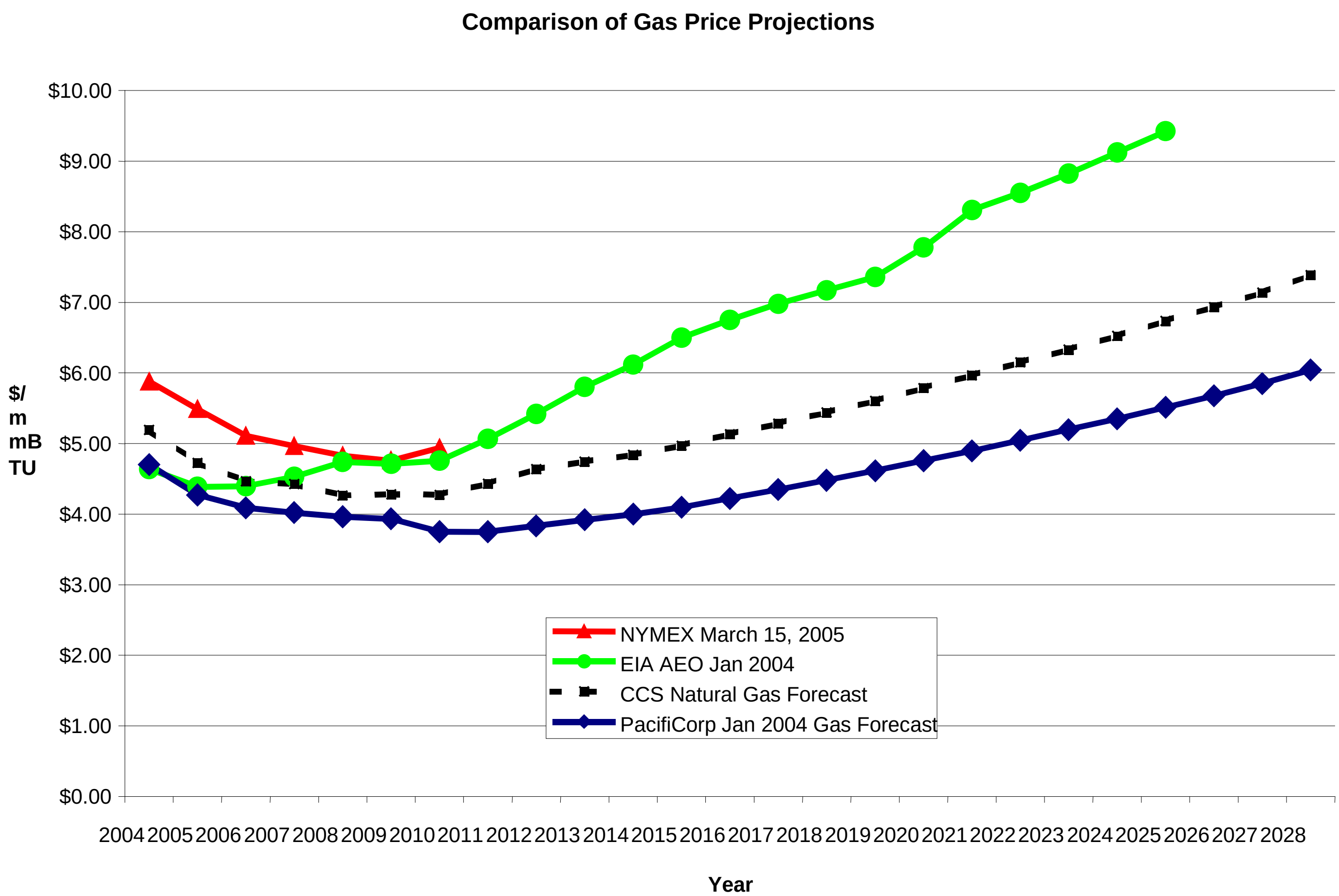
Levelization rates are used to convert the overnight cost to construct a generating plant (SCCT - $595/kW and CCCT - $726/kW) to the annual revenue requirement values that would be required to fully recover the cost of building the plant. PacifiCorp has chosen to express the costs as a real levelized carrying charge value; thus it uses a real levelized rate to convert the overnight costs to the annual revenue requirement.

PacifiCorp has increased its levelized carrying costs slightly, for both the SCCT and CCCT units, from what it had filed initially in September 2003. The September 2003 filing was based on data developed for the 2003 IRP, while the January 2004 filing was based on data developed for the IRP Update in November 2003. Although the change between the September 2003 and January 2004 filings is insignificant, the change between what is presently in effect and the current filing are much more substantial and require additional explanation. The Committee has requested this additional information in a data request that is outstanding. However, as the data in the September 2003 filing was based on the 2003 IRP, and given that the 2003 IRP has been acknowledged by the Commission, the Committee does not at this time believe that there are any significant problems with using PacifiCorp's proposed levelization values.

3.2.4 Fuel Costs

The Committee has conducted a detailed review of the Company's natural gas fuel price assumptions. The Company's natural gas forecast appears to be somewhat low compared with other natural gas forecasts that the Committee has used in its analysis. This comparison led the Committee to develop and recommend its own forecast as an alternative. Figure 4 compares the natural gas price forecasts that the Committee analyzed with the forecast it has developed.

Figure 4


Comparison of Gas Price Projections
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
$/ mmBTU
2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028
Year
NYMEX March 15, 2005
EIA AEO Jan 2004
CCS Natural Gas Forecast
PacifiCorp Jan 2004 Gas Forecast

The graph above shows four projections. The Department of Energy's EIA projection is based on the gas price forecast developed for its Annual Energy Outlook, released in January 2004. The NYMEX projection was obtained from the NYMEX website and represents the price today that buyers would be willing to pay for deliveries of natural gas at a future point in time. The Committee's projection was developed as an alternative to PacifiCorp's gas price forecast, which is the lowest forecast on the graph above, and to the NYMEX or EIA forecasts, which represent much higher forecasts. An adjustment to the Committee's forecast has been made to account for the fact that PacifiCorp is able to take advantage of lower cost gas purchased at the OPAL trading hub, as compared to the Henry Hub, which the other forecasts are based on. The "basis adjustment" amounts to a 40 cents per year reduction in gas prices.

The graph shows that in the short run, EIA, NYMEX, and PacifiCorp's OPAL forecasts are not significantly different. Over the longer term, the NYMEX forecast appears to be headed in the same direction as the EIA forecast, although the Nymex forecast only goes out to 2010. The EIA forecast goes out to 2025 and appears to be significantly higher than what PacifiCorp forecasts. PacifiCorp's price in 2025 is nearly 4$/mmBtu lower than EIA's in that year. This will have a significant impact on the avoided energy cost calculation. As a general rule, when avoided energy costs are priced based on the cost of a natural gas CCCT unit, for every $1/mmBTU increase in the price of natural gas, the avoided energy cost would increase by about $7/mWh. Assuming a 200 MW QF produces about 1,500 gWh based on an 85% capacity factor, then for every $1/mmBTU increase in the price of natural gas, total avoided cost payments would increase by about $10 million. Volatility in the price of natural gas, therefore, can have a dramatic impact on the avoided cost results.

The Committee is comfortable with its forecast of natural gas prices for purposes of developing Schedule 37 avoided cost payments and recommends that the Commission adopt its projection of natural gas prices. However, based on the natural gas price impact just illustrated, the Committee is concerned about locking avoided costs to a single gas price forecast. This may lead to payments that do not reflect actual operating costs at the time payments to the QFs are made, which could harm either the QF or ratepayers.

If the Commission prefers to use actual natural gas prices, the Committee recommends that an additional calculation be performed at the time that avoided cost payments are made to QFs. At some future point in time when a QF delivers power to PacifiCorp, an accounting adjustment could be performed to index the avoided energy cost payment to the actual cost of gas at that time. To do this, an implied heat rate calculation is performed by dividing the annual avoided energy cost by the annual average fuel cost that was used in the avoided cost determination. If the implied heat rate is less than the heat rate of a CCCT, then no further adjustment is necessary as the fuel price is assumed to be reasonable under that circumstance. If the heat rate is determined to be greater than the heat rate of a CCCT, then an adjustment is made to the fuel cost used in the avoided cost calculation. In that case, the actual Opal Hub market natural gas price should be multiplied by the implied heat rate at the time the avoided cost payment is made. This adjustment ensures that QFs are neither underpaid nor overpaid for the energy they provide to PacifiCorp.

3.2.5 Comparison of Avoided Cost Results

In previous sections, the Committee has recommended both adjustments to PacifiCorp's avoided cost methodology and a change to PacifiCorp's gas price forecast. Table 3 below provides a comparison of several sets of avoided costs, including the Committee's proposed avoided costs on a $/MWH basis.

(Begin Confidential)

Comparison between Proposed and Current Avoided Costs - Table 3

Year	PacifiCorp's Avoided Costs Filed in 2001 ($/MWH)	PacifiCorp's Current Avoided Costs as filed in 2002 ($/MWH)	PacifiCorp's Proposed Avoided Costs filed in Sept 2003 ($/MWH)	PacifiCorp's Proposed Avoided Costs filed in Jan 2004 ($/MWH)	Committee's Modifications to PacifiCorp's Jan 2004 avoided cost filing ($/MWH)	Market Revenues available to Currant Creek from Round II Bid Evaluation ($/MWH)
2003	$43.02	$47.38	$45.81			
2004	$42.22	$44.10	$46.77	$33.36	$36.22	Confidential
2005	$41.43	$38.77	$61.39	$44.07	$46.99	Confidential
2006	$40.85	$39.66	$52.15	$41.89	$44.90	Confidential
2007	$41.18	$39.89	$43.28	$42.71	$45.85	Confidential
2008	$42.01	$40.66	$44.23	$45.86	$48.30	Confidential
2009	$41.93	$40.88	$43.97	$45.97	$48.76	Confidential
2010	$41.93	$41.17	$42.01	$44.90	$49.04	Confidential
2011	$42.84	$41.86	$41.30	$45.25	$50.58	Confidential
2012	$43.83	$42.76	$42.52	$46.23	$52.51	Confidential
2013	$44.90	$43.79	$43.75	$47.25	$53.74	Confidential
2014		$44.42	$41.21	$48.25	$54.94	Confidential
2015		$45.18	$42.07	$49.44	$56.30	Confidential
2016		$45.78	$44.25	$50.86	$57.93	Confidential
2017		$46.33	$46.29	$52.19	$59.47	Confidential
2018		$47.07	$47.53	$53.61	$61.16	Confidential
2019		$47.75	$48.86	$55.05	$62.90	Confidential
2020		$48.66	$50.25	$56.63	$64.72	Confidential
2021			$50.70	$58.21	$66.61	Confidential
2022			$52.03	$59.81	$68.52	Confidential
2023			$53.43	$61.41	$70.36	Confidential

(End Confidential)

Table 1 demonstrates three things. First, it shows how PacifiCorp's filed avoided costs have changed over the 2001-2004 period. The changes in avoided costs over time are not surprising given changes that have occurred in data assumptions, such as natural gas price forecasts. Over the long term, PacifiCorp's avoided costs have been comparable. Conversely, PacifiCorp's calculation of short term avoided costs have differed substantially, and this has largely been driven by differences in the avoided cost methodology that PacifiCorp has used for the calculation of short term avoided costs.

Second, Table 3 compares the Committee's proposed avoided costs to PacifiCorp's avoided costs filed in January 2004. Over the entire period, the Committee proposes higher avoided costs compared to what PacifiCorp has filed. In the short term, the higher costs are driven by the fact that the Committee recommends using more months in the calculation of avoided capacity costs, as well as a higher natural gas price forecast. In the long run, the differences are solely driven by the higher natural gas price forecast. The Committee believes these differences are reasonable. It is not the Committee's intent to advocate for higher avoided costs than necessary. The Committee believes that these costs are reflective of what PacifiCorp will incur and therefore avoid by purchasing capacity and energy from the QFs.

Third, Table 3 indicates the market price curves that PacifiCorp developed and used during the Currant Creek proceedings. These market price curves are another measure of future avoided costs.

3.3 Increase in the Capacity Limit for Wind Power QFs

A group of petitioners including the Utah Energy Office, Wind Tower Composites LLC, Utah Clean Energy Alliance, Wasatch Clean Air Coalition, Renewable Energy Development Corporation, and Tasco Engineering (Petitioners), requested the Commission consider increasing the size of the QF capacity limit for Schedule 37 avoided costs for wind power QFs exclusively from1 MW to a maximum of 3 MW.

If the Commission decides to permit an increase in size, the Committee recommends limiting Schedule 37 avoided cost payments to wind power QFs that are 3 MW or less. Schedule 37 is an administrative convenience for QFs that are small and that do not have the resources or the ability to go through the contracting process associated with the Schedule 38 avoided cost tariff. The larger the QF the greater its ability to enter into contract negotiations with PacifiCorp. Assuming a QF installed cost of $1,000/kW, the cost of constructing a 1 MW wind power QF is $1,000,000, and the cost to construct a 3 MW QF is $3,000,000. The Committee can only assume that a company willing to invest anything more than $3,000,000 would have the financial means to negotiate a contract with PacifiCorp. Furthermore, based on the petitioners' own filing, it states that a 3 MW wind turbine most likely would be equivalent in energy output terms to that of a 1 MW fossil fuel fired QF. Therefore, to increase the size beyond 3 MW would give an unfair advantage to wind power QFs over fossil fuel QFs

The Committee notes that the Commission may want to defer making a decision regarding a change to Schedule 37 for wind-powered QFs until Schedule 38 has been examined.

The renewable energy implications in PacifiCorp's Schedule 38 testimony may need to be considered more fully before a decision is made.

.