ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM QUALIFYING FACILITIES THAT QUALIFY FOR SCHEDULE NO. 37

UTAH – MAY 2014

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Overview

In compliance with the Commission's February 12, 2009, Order in Docket No. 08-035-78 on Net Metering Service, PacifiCorp (the "Company") calculates and files Schedule No. 37 avoided costs annually in order to establish the value or credit for net excess generation of large commercial customers under the Schedule No. 135 Net Metering Service.[1] To perform this calculation, the Company uses the Commission approved Schedule No. 37 avoided cost methodology prescribed in Docket No. 94-2035-03, as modified by Docket Nos. 03-035-T10 and 12-035-T10. In this filing the Company has incorporated various findings in the Commission's Orders in Docket 12-035-100 that are also applicable to avoided costs in Schedule No. 37.

Resource Sufficiency / Deficiency Period

In its November 28, 2012, order in Docket No. 12-035-T10 the Commission clarified the methodology to be used to determine the resource sufficiency and deficiency period. The Commission Ordered:

> We will rely on the Company's [Integrated Resource Plan (IRP)] process and the Company's planned actions as articulated in its IRP or IRP update action plans as the basis for identifying the type and timing of a deferrable resource and therefore the time period in which the proxy plant method will be used to calculate energy and capacity payments for Schedule 37 during the period of resource deficiency.

1 Docket No. 08-035-78, February 12, 2009 Order, U.P.S.C 24 (2009).

Table 1 presents the timing of deferrable resources as listed in Table 5.5 of the Company's 2013 IRP Update dated March 31, 2014. Table 1 shows that the Company intends to acquire several combined cycle combustion turbines ("CCCT") including a 645 MW CCCT in 2014 and a 423 MW CCCT in 2027. The Company has begun construction of the 645 MW Lake Side 2 CCCT scheduled to come online in 2014, so the 423 MW CCCT scheduled for 2027 is the Company's next deferrable resource in the 2013 IRP Update and 2027 marks the start of the avoided cost resource deficiency period.

In its Order in Docket No. 09-035-T14, the Commission directed the Company "to label Table 1 with the applicable planning reserve margin assumption (e.g., 12 or 15 percent) in all subsequent filings of Schedule No. 37 rates." The IRP uses planning reserves to account for operating reserves, regulating reserves, load forecast errors and other planning uncertainties. As shown on Table 1, the 2013 IRP Update utilized a 13 percent planning reserve margin.

Although the IRP action plan now governs the determination of the resource deficit period, the Company has also traditionally prepared a load and resource balance using its Generation and Regulation Initiative Decision Tools ("GRID") production cost model to determine the number of months during the resource sufficiency period in which the Company is capacity short.[2] The Company prepared a GRID-based load and resource balance using the existing resource portfolio and has included the results in Confidential Appendix 3 in this filing.

Avoided Cost Calculation

Based on the timing of the next deferrable resource shown in **Table 1**, the avoided cost calculation is separated into two distinct periods: (1) the Short Run – a period of resource

[2] See Docket No. 03-035-T10, June 1, 2004 Order, U.P.S.C. 16 (2004) and Docket No. 12-035-T10, November 28, 2012 Order, U.P.S.C. 7 (2012)

sufficiency (2014 through 2026); and (2) the Long Run – a period of resource deficiency (2027 and beyond).

Consistent with the Commission's August 16, 2013, order in Docket No. 12-035-100, avoided costs are adjusted for wind and solar qualifying facilities ("QFs") to reflect the approved capacity contribution. Avoided costs are also adjusted for wind and solar qualifying facilities ("QFs") to reflect integration costs. Solar resources are distinguished as configured either to maximize energy output (Fixed Solar) or to maximize output during peak load periods or with a tracking device (Tracking Solar). In its order the Commission determined the capacity contribution for wind, fixed solar, and tracking solar to be 20.5%, 68%, and 84%, respectively. **Table 12** provides the details of the approved level of integration costs for wind and solar resources.

1. Short Run Avoided Costs

During periods of resource sufficiency, the Company's avoided energy costs are based on the displacement of purchased power and existing thermal resources as modeled by the Company's GRID model. The results of the GRID analysis are provided in Confidential Appendix 4.

To calculate short-run avoided costs, two production cost studies are prepared. The only difference between the two studies is an assumed 10 aMW resource in northern Utah, at zero running cost. The 10 aMW resource serves as a proxy for qualifying facility generation. The avoided energy cost could be viewed as the highest variable cost incurred to serve total system load from existing and non-deferrable resources. The outputs of the production cost model run are provided in **Table 2**. Tables 2B, 2C, and 2D are provided for wind, solar-fixed and solar-tracking QF types, respectively, which include the impact of integration costs during the short run period.

Capacity payments based on a Simple Cycle Combustion Turbine during the sufficiency period have been removed consistent with the Commission's order in Docket No. 12-

035-100 and consistent with the Company's 2013 IRP and IRP Update. Prior to the start of the deficiency period in 2027, the Company will not procure additional thermal capacity resources; rather, it will utilize front office transactions, or wholesale market purchases, to meet its needs.

Table 11 summarizes the monthly capacity deficits as modeled in GRID, even though they are no longer applicable since capacity payments during the sufficiency period are removed.. Supporting details for **Table 11** are provided in Confidential Appendix 3.

In the Commission's Order dated October 31, 2011, in Docket 11-035-T06 the Commission directed the Company to show how hedging gains and losses relate to the Schedule 37 rates. Hedging gains and losses are included as a fixed cost in the GRID studies used to calculate short-run avoided energy costs in the same manner as they are included in general rate case proceedings. In the calculation of short-run avoided costs, natural gas hedging gains and losses allocated to gas-fired resources fluctuate to the extent plant dispatch is altered by the addition of the 10 aMW zero cost resource.

2. *Long Run Avoided Costs*

During the resource deficiency period (2027 and beyond), avoided costs are the fixed and variable costs of a proxy resource that could be avoided or deferred. The current proxy resource is a combined cycle combustion turbine ("CCCT").[3]

Since CCCTs are assumed to be built as base load units that provide both capacity and energy under the Utah Schedule 37 methodology, it is appropriate to split the fixed costs of this unit into capacity and energy components. The fixed cost of a SCCT, which is assumed to be acquired as a capacity resource under the Utah Schedule 37 methodology, defines the portion of the fixed cost of the blended resource that is assigned to capacity.

[3] 423 MW CCCT Dry "J", Adv 1x1 - East Side Resource (5,050') as listed in the 2013 IRP Update. Fuel costs are from the Company's March 2014 Official Forward Price Curve.

Consistent with the Commission Order in Docket No. 03-035-14, 50% of the fixed costs associated with the construction of the CCCT resource in excess of the fixed costs of a SCCT are assigned to energy and are added to the variable production (fuel) costs of the CCCT resource to determine the total avoided energy costs. **Table 3** shows the capitalized energy costs.

The fuel cost of the CCCT defines the avoided variable energy costs. The gas price forecast used as the basis for the CCCT fuel cost is discussed later in this document. **Table 4** shows the CCCT fuel cost, the addition of capitalized energy costs at an assumed 51.9%[4] capacity factor and the total avoided energy costs.

Because energy generated by a qualifying facility may vary, the total avoided costs at 75%, 85% and 95% capacity factor are prepared to illustrate the impact of differing generation levels. This calculation is shown in **Table 5**.

Avoided energy costs can be differentiated between on-peak and off-peak periods. To make this calculation, the Company assumed that all capacity costs are incurred to meet on-peak load requirements. On an annual basis, approximately 56% of all hours are on-peak and 44% are off-peak. **Table 6** shows the calculation of on-peak and off-peak avoided energy prices.

For informational purposes, **Table 7** shows a comparison between the avoided costs currently in effect in Utah and the proposed avoided costs in this filing for a base load QF. The 20 year nominal levelized prices are calculated using a 6.882% discount rate[5] as listed on page 39 of the 2013 IRP Update.

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[4] The 51.9% capacity factor is the combined energy weighted capacity factor of the CCCT Dry "J", Adv 1x1 resource (56%) and the CCCT Dry "J", Adv 1x1 duct firing (16%) included in the 2013 IRP. See Table 6.2 in the 2013 IRP.

[5] The discount rate equates to PacifiCorp's after-tax weighted cost of capital.

Table 8 shows the calculation of the total fixed costs and fuel costs of the CCCT and SCCT that are used in **Table 3** and **Table 4**. In this filing, the Company's next deferrable resource is a CCCT located on the east side of the Company's system. This result is consistent with the Company's addition of an east side CCCT in 2027 as modeled in the 2013 IRP Update. Costs and the payment factors are listed in Tables 6.1 and 6.2 of the 2013 IRP and did not change in the 2013 IRP Update.

Price Forecast for Electricity and Natural Gas

The natural gas price used in this filing is from the Company's Official Forward Price Curve ("OFPC") dated March 31, 2014. Forward prices for electricity are based on the March 31, 2014, OFPC but have been adjusted to remove the impact of a carbon tax. The Company has historically included a carbon tax in its determination of forward market prices which served as a surrogate for future regulation of CO2 emissions at the federal level. Excluding the impact of a carbon tax from the forward market prices is consistent with the Commission's order in Docket No. 12-035-100 where it concluded that no specific adjustments should be made for environmental costs.

Both the electricity and natural gas prices are inputs to the Company's GRID model in the calculation of the proposed avoided costs. **Table 9** shows the natural gas price used to calculate the fuel costs of the CCCT that is the proxy resource for the Long Run avoided costs, and **Table 10** shows the electricity prices at Mid-Columbia and Palo Verde that are used in the Company's avoided cost calculation on a heavy-load hour and light-load hour basis.

For the period from 2014 through April 2020, the forward prices are based on the information from market transactions. For the period from May 2020 through April 2021, the official forward prices are the average of market information and the long-term price forecast. For period beginning in May 2021 and beyond, the forward prices are based on the long-term price forecast.