ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

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

UTAH – APRIL 2016

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Overview

Schedule 37 contains avoided cost prices to be paid to small qualifying facilities (QF) and applies to QFs with a design capacity of 1 MW or less for qualifying cogeneration facilities and 3 MW or less for small power production facilities. Prices are available for a cumulative total of 25 MW. 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, 12-035-T10, and 15-035-T06. This filing is consistent with the methodology used for development of currently effective rates approved by the September 18, 2015 Commission order in Docket No. 15-035-T06.

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

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

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.

Table 1 presents the timing of deferrable resources as listed in Table 5.3 of the Company's 2015 IRP Update filing dated March 31, 2016. Table 1 shows that the Company intends to acquire several combined cycle combustion turbines ("CCCTs") including an East side 635 MW CCCT and West side 477 MW CCCT, both starting in 2028. The Company's next deferrable resource in the 2015 IRP Update is scheduled for 2028, which 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 2015 IRP Update utilized a 13 percent planning reserve margin.

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 sufficiency (2016 through 2027); and (2) the Long Run – a period of resource deficiency (2028 and beyond).

Consistent with the Commission's January 16, 2015 and February 13, 2015 orders in Docket Nos. 14-035-T04 and 14-035-55, avoided costs are adjusted for wind and solar qualifying facilities ("QFs") to reflect the approved capacity contribution. In its June 26, 2015, order in Docket No. 14-035-140, the Commission specified the capacity contribution to be applied to renewable resources for avoided cost pricing. Shown below are the capacity contributions used in the study. Consistent with that study, solar resources are differentiated between fixed tilt projects ("Fixed Solar") and single axis

tracking projects ("Tracking Solar") and the tariff has been updated to reflect these definitions.

Renewable Type	Capacity Contribution - Percent of Nameplate
Wind	14.5%
Solar – Fixed Mount	34.1%
Solar –Tracking	39.1%

Avoided costs are also adjusted for wind and solar QFs to reflect integration costs. **Table 10** 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 costs are based on the displacement of purchased power, existing thermal resources and FOTs from the 2015 IRP Update as modeled by the Company's GRID model. To calculate short-run avoided costs, two GRID 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 QF generation. The avoided cost could be viewed as the highest variable cost incurred to serve total system load from existing and non-deferrable resources.

Avoided costs are differentiated into on-peak and off-peak rates based on the relationship of Palo Verde on-peak and off-peak market prices to Palo Verde flat market prices, respectively. The outputs of the GRID production cost model run and the differentiated on-peak and off-peak avoided costs are provided in **Table 2A**. **Tables 2B**, **2C**, and **2D** for wind, solar-fixed and solar-tracking QF types, respectively, which include the impact of integration costs during the short run period. The results of the GRID runs are provided in Confidential Appendix 3 ("UT Sch 37 - Appendix - 3a - GRID AC Study CONF _2016 04 25" " and "UT Sch 37 - Appendix - 3b - GRID AC Study CONF _2016 04 25" ".

Consistent with the Commission Order dated September 18, 2015 in Docket No. 15-035-T06 and the Company's 2015 IRP Update, prior to the start of the deficiency period in 2028 the Company will not procure additional thermal capacity resources; rather, it will utilize front office transactions, or short-term wholesale market purchases, to meet its needs.

The Commission's Order dated October 31, 2011, in Docket 11-035-T06, 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 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 (2028 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 blend of the two CCCTs scheduled for 2028.[2]

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

[2] A 477 MW West Side, CCCT - Dry "J", Adv 1x1 and a 635MW East Side, CCCT - DJohns Dry "F", 2x1, from 2015 IRP Update, Table 5.3. Fuel costs are from the Company's March 2016 Official Forward Price Curve.

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 69.5%[3] capacity factor and the total avoided energy costs.

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 5** shows the calculation of on-peak and off-peak avoided energy prices.

For informational purposes, **Table 6** 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 15-year nominal levelized prices are calculated using a 6.66% discount rate[4] as listed on page 39 of the 2015 IRP Update.

Table 7 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 blended CCCT, where proxy costs are based on weighted average of costs of the two CCCTs scheduled for 2028 (477 MW West side CCCT and 635 MW East side CCCT). Costs and the payment factors for each of these CCCTs are listed in Tables 6.1 and 6.2 of the 2015 IRP. The CCCT characteristics used in the 2015 IRP Update were unchanged from the 2015 IRP.

[3] The 69.5% capacity factor is the combined energy weighted capacity factor of the two CCCTs, including their duct firing units, as included in the 2015 IRP. See Table 6.2 in the 2015 IRP.
[4] The discount rate equates to PacifiCorp's after-tax weighted cost of capital.

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, 2016. Forward prices for electricity are based on the March 31, 2016, OFPC.

Both the electricity and natural gas prices are inputs to the Company's GRID model in the calculation of the proposed avoided costs. **Table 8** 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 9** 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.