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An Examination of Avoided Costs in Utah

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To	Utah Energy Office
From	Mark Bolinger and Ryan Wiser, Lawrence Berkeley National Laboratory
Subject	An Examination of Avoided Costs in Utah
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Introduction

The Utah Wind Working Group (UWWG) believes there are currently opportunities to encourage wind power development in the state by seeking changes to the avoided cost tariff paid to qualifying facilities (QFs). These opportunities have arisen as a result of a recent re-negotiation of Pacificorp's Schedule 37 tariff for wind QFs under 3 MW, as well as an ongoing examination of Pacificorp's Schedule 38 tariff for wind QFs larger than 3 MW. It is expected that decisions made regarding Schedule 38 will also impact Schedule 37. Through the Laboratory Technical Assistance Program (Lab TAP), the UWWG has requested (through the Utah Energy Office) that LBNL provide technical assistance in determining whether an alternative method of calculating avoided costs that has been officially adopted in Idaho would lead to higher QF payments in Utah, and to discuss the pros and cons of this method relative to the methodology recently adopted under Schedule 37 in Utah.

To accomplish this scope of work, I begin by summarizing the current method of calculating avoided costs in Utah (per Schedule 37) and Idaho (the "surrogate avoided resource" or SAR method). I then compare the two methods both qualitatively and quantitatively. Next I present Pacificorp's four main objections to the use of the SAR method, and discuss the reasonableness of each objection. Finally, I conclude with a few other potential considerations that might add value to wind QFs in Utah.

Summary of Pacificorp Schedule 37 in Utah

Qualifying facilities of up to 3 MW in nameplate capacity (with a cumulative cap of 25 MW) are eligible for published avoided cost rates under Schedule 37. The method used to calculate Schedule 37 rates has two parts, depending on whether Pacificorp has sufficient or deficient resources. During periods of resource sufficiency (believed to be through mid-2007), a production cost model is used to determine short-run avoided costs. During periods of resource deficiency (after mid-2007), the capital and operating costs of a proxy plant are used to calculate avoided costs.

Resource Sufficiency Period
From 2004 through mid-2007, Pacificorp contends that it has sufficient energy and winter capacity, but is capacity-deficient during the summer months. During that period, avoided costs equal the cost avoidance of adding a 10 MW zero-cost resource to the system, plus avoided summer capacity costs. Specifically, Pacificorp conducts two production-cost modeling runs – one a baseline run, and the other including a 10 MW zero-cost resource. The difference in overall cost between the two runs, plus the avoided capacity costs of a simple-cycle combustion turbine (SCCT) during the summer months, equals the total avoided costs during the sufficiency period.

Resource Deficiency Period
From mid-2007 on, Pacificorp bases avoided costs on the capital and operating costs of a proxy plant, in this case considered to be a combined-cycle gas combustion turbine (CCCT) with cost and operating characteristics equal to Pacificorp's new Currant Creek unit (see Table 1 below). In order to "accurately" split QF prices during the proxy period into capacity and energy prices, however, Pacificorp introduces a SCCT into the picture as well. Specifically, the fixed cost of a SCCT, which is usually acquired as a capacity resource, defines the portion of the fixed cost of the CCCT that is assigned to capacity. Because CCCTs have higher fixed costs (but lower operating costs) than SCCTs, however, the fixed costs of a CCCT that exceed those of a SCCT are capitalized and assigned to energy payments ("capitalized energy costs"). This has the effect of reducing capacity prices and increasing energy prices relative to what each would have been if the proxy CCCT costs had been applied without modification.

Other Notable Provisions

- *Fuel Price Index:* Pacificorp has stated that the Opal pricing point in Wyoming is the relevant basis for any gas price inputs in Utah. It proposed using its own forecast of Opal prices, which consisted of a blend of near-term forward prices and a long-term price forecast from PIRA. The Utah Public Service Commission ultimately accepted a natural gas price projection that was an average of Pacificorp's forecast and another proposed by the Committee of Consumer Services. The delivered starting price in 2004 for this average gas price projection is $4.98/MMBtu and the average annual nominal escalation rate is 0.8%/year from 2004-2023. Given the EIA's latest inflation forecast from AEO 2005, this 0.8%/year nominal escalation rate translates into a -1.59% real escalation rate; i.e., the gas price forecast used in Schedule 37 shows gas prices *declining* over time in real or constant dollar terms.
- *Payment Schedule:* Under Schedule 37, a QF has the option of being paid either (A) a capacity and average energy price payment, or (B) winter and summer energy payments for peak and off-peak hours. Assuming steady output throughout all hours of the year, the two pricing options equal one another. A wind generator QF that selects option A (the capacity and average energy payment) will be paid a reduced capacity payment equal to 20% of the stated capacity price multiplied by the QF capacity. This is to account for the low capacity value of wind power.
- *Renewable Energy Credits (RECs):* Pacificorp has argued that its ratepayers should hold title to the RECs. The Committee of Consumer Services has agreed that consumers should get the RECs, and ultimately advocated for the formation of a task force to study the issue

and develop a report by the end of 2004. I have not been able to find any information on this task force or their findings.

Summary of the Surrogate Avoided Resource (SAR) Method Used in Idaho

QFs up to 10 MW are eligible for published avoided cost rates in Idaho. On September 26, 2002, the Idaho Public Utilities Commission (IPUC) issued Order No. 29124, which modified how QF prices would be set in Idaho. Prior to Order No. 29124, the IPUC considered resource sufficiency and deficiency periods in much the same way as is currently done under Utah Schedule 37. Specifically, during resource sufficiency periods, avoided costs were set to equal surplus energy costs, while during resource deficiency periods, avoided costs included both the energy and capacity costs of the surrogate avoided resource (SAR). Order No. 29124 eliminated consideration of resource sufficiency/deficiency periods (for reasons discussed below), and instead based avoided costs over the entire contract period on the energy and capacity costs of the SAR. As is the case in Utah under Schedule 37, the SAR or proxy plant is considered to be a CCCT.

One obscure but notable aspect of the Idaho methodology is the inclusion of a "tilting rate" intended to account for the fact that the SAR is assumed to have a 30-year life, which is longer than the 20-year QF contract. Because the assumed life of the SAR extends beyond the QF contract term, the SAR need not recover its entire capital costs through the QF contract. In Idaho, the tilting rate equals the assumed rate of inflation, and has the effect of reducing the assumed plant cost to about 82% of the stated cost (i.e., only 82% of the cost of the SAR is recovered through the 20-year QF contract).

Other Notable Provisions

- *Fuel Price Index:* Fuel price assumptions are based on the Northwest Power Planning Council's (NWPPC) medium "east-side delivered" fuel price forecast, and are updated each time NWPPC updates its forecast. Rather than adopt the forecast as is, the specific methodology employed is to average the price of the three years leading up to and including the current year,[1] and then escalate that averaged starting price at the annualized rate of escalation inherent over the entire forecast period. This method results in a "straight line" fuel price input that is nevertheless based on the NWPPC forecast. The most recent delivered starting price in 2004 for this average gas price projection is $5.10/MMBtu and the average annual nominal escalation rate is 2.3%/year. Given the EIA's latest inflation forecast from AEO 2005, this 2.3%/year nominal escalation rate translates into a -0.12% real escalation rate; i.e., the gas price forecast used in Idaho shows gas prices essentially flat over time in real or constant dollar terms.
- *Payment Schedule:* Published avoided costs in Idaho do not break out capacity and energy payments. Instead, a single non-levelized $/MWh payment stream (for non-fueled QFs) is presented, along with the equivalent levelized price for contracts ranging in length from 1 to 20 years. It should be noted, however, that the IPUC has allowed Idaho Power to apply "seasonalization factors" to the non-levelized price stream in order to convert it from a

[1] The purpose of the three-year averaging is to avoid the possibility of a very high-priced single year resulting in a high starting price that skews payments upwards over the duration of the contract.

single price each year to three different prices depending on season. Assuming steady output throughout the year, the weighted average seasonal price will equal the published non-levelized price. For wind generators with variable output, however, the seasonal weighting will likely somewhat reduce the weighted-average price received. For example, in a recent PPA between Idaho Power and a wind QF, seasonal weighting reduced the published price by about $1.15/MWh on a levelized basis over 22 years (see Figure 5, and discussion surrounding it, below).

- *Renewable Energy Credits (RECs):* RECs are retained by the QF, and are not transferred to the utility. Indeed, the IPUC has ruled that RECs would not be a recoverable cost, so the utilities have little interest in them. Hence, the sale of RECs may represent an incremental revenue stream available to the QF, above and beyond the avoided cost payment.

Comparison of Utah Schedule 37 to Idaho SAR Methodology

The main methodological differences between Utah Schedule 37 and the SAR method employed in Idaho are (1) the former's consideration of resource sufficiency and deficiency periods; (2) the former's use of a SCCT to explicitly disaggregate total avoided costs into energy and capacity payments; and (3) differences in the way wind generation is de-rated to account for low capacity value (i.e., assignment of 20% of full capacity value in Utah, versus seasonal weighting of the published price in Idaho). Since – absent access to Pacificorp's production cost model – I cannot replicate the resource-sufficient portion of the Schedule 37 avoided costs, the rest of this memo will focus primarily on the proxy (i.e., resource-deficient) portion of Schedule 37 avoided costs. Differences in methodology and input assumptions during the deficiency period will be highlighted.

During the resource deficiency period, the SAR and Schedule 37 methods are similar, in that both make use of a surrogate or proxy plant, with comparative cost and performance characteristics listed in Table 1. In addition, Table 1 shows the capital-carrying charge (called a "payment factor" in Utah) used to amortize the plant cost, the weighted-average cost of capital (which serves as the discount rate for levelization purposes), and the fuel price projections. Not shown in Table 1 are the cost and performance characteristics of the SCCT used in Utah to allocate total avoided costs to capacity and energy payments (use of the SCCT does not appear to impact overall avoided costs, but rather only the allocation between capacity and energy payments).

Table 1. Comparison of Proxy Plant (Utah Schedule 37) and SAR (Idaho)

	Utah (2004)	Idaho (2004)
Plant Cost ($/kW)	$726	$738 ($604 after application of tilting rate)
Fixed O&M ($/kW-year)	$9.72	$11.90
Variable O&M ($/MWh)	$2.57	$3.11
Heat Rate (Btu/kWh)	7,626	7,100
Capacity Factor	85%	92%
Plant Life (years)	30	30
Capital Carrying Charge*	8.71% (Pacificorp)	12.60% (Pacificorp)
WACC (Discount Rate)	7.52% (Pacificorp)	10.27% (Pacificorp)
Fuel Price Projections	Average of Pacificorp and Committee of Consumer Services forecasts: $4.98/MMBtu in 2004, escalating at 0.8%/year	Based on NWPPC forecast: $5.10/MMBtu in 2004, escalating at 2.3%/year

*Called a "Payment Factor" in Utah

Based partially on the assumptions listed in Table 1 (again, Table 1 does *not* include assumptions in place during the resource sufficiency period, or assumptions concerning the SCCT used to allocate avoided costs into capacity and energy payments during the resource deficiency period), Figure 1 compares Pacificorp's *published* non-levelized and levelized avoided costs in Idaho (as approved on December 1, 2004 in Order No. 29646) to those published in Schedule 37 in Utah (the "capacity and average energy price payment" option is shown, assuming *full* capacity payment). In both cases, the avoided costs shown are applicable only to *non-wind QFs*, as a wind QF in Utah would earn a reduced capacity payment (just 20% of the full value) while a wind QF in Idaho would likely receive a seasonal-weighted price that is a bit lower than depicted in Figure 1. As shown, for the same utility (Pacificorp), non-wind QFs earn about $10/MWh more in Idaho than they do in Utah.

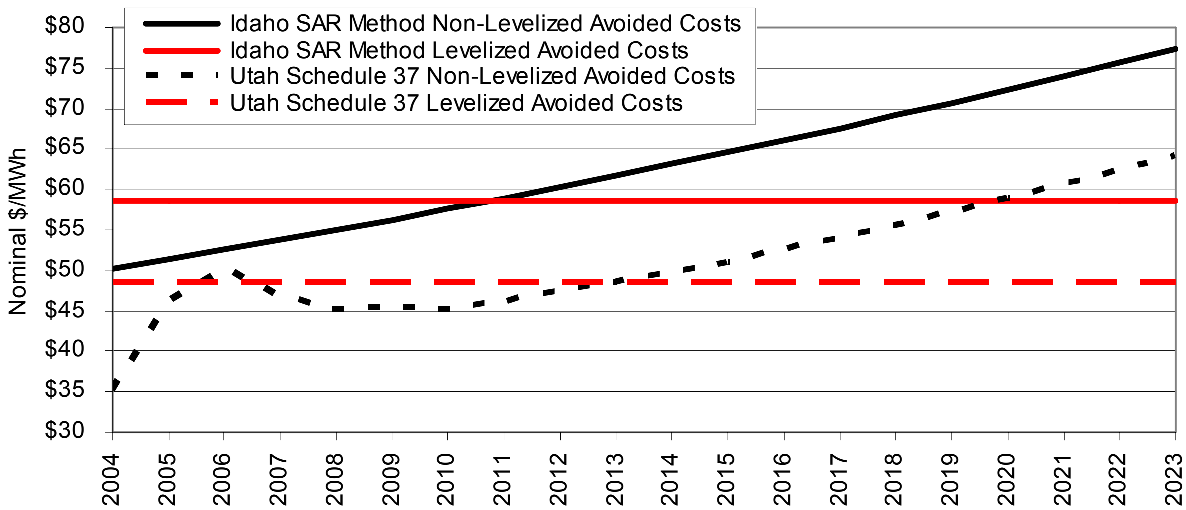

Figure 1. Published Avoided Costs for Non-Wind QFs in Idaho and Utah (Pacificorp)

Based on the methodology described in Idaho Order No. 29124, the variables described in the documentation leading up to Idaho Order No. 29646, and consultation with staff at the Idaho PUC, I have been able to replicate the non-levelized and levelized avoided costs approved by the Idaho PUC on December 1, 2004 and published in Order No. 29646. With the correct methodology in hand, it is a trivial matter to change the input assumptions from those used in Idaho to those that are currently used in Utah under Schedule 37 (i.e., switching the inputs from the second to the first column of Table 1).

Figure 2 shows the results of plugging Utah-specific parameters (i.e., those used in the calculation of Schedule 37 avoided costs during the resource deficiency period) into the SAR methodology as employed in Idaho. As was the case in Figure 1, the avoided costs depicted in Figure 2 are those that would be earned by *non-wind* QFs able to generate flat blocks of power throughout the year, such that any seasonal weighting would not devalue the published price (under the SAR method) and the QF would earn the full capacity payment (under Schedule 37). As shown, the gap between the SAR method and the Schedule 37 method narrows considerably once consistent, Utah-specific input assumptions are used in each method. Whereas the gap between levelized prices shown in Figure 1 was about $10/MWh, under common, Utah-specific assumptions the gap declines to about $4.25/MWh ($52.87/MWh vs. $48.62/MWh). This suggests that for non-wind QFs, differences in input assumptions (e.g., fuel price projections, capital carrying charges, etc.) account for about $5.75/MWh of the total levelized price difference between Idaho and Utah, while differences in methodology (i.e., consideration of resource sufficiency/deficiency periods in Utah) account for the remaining $4.25/MWh.

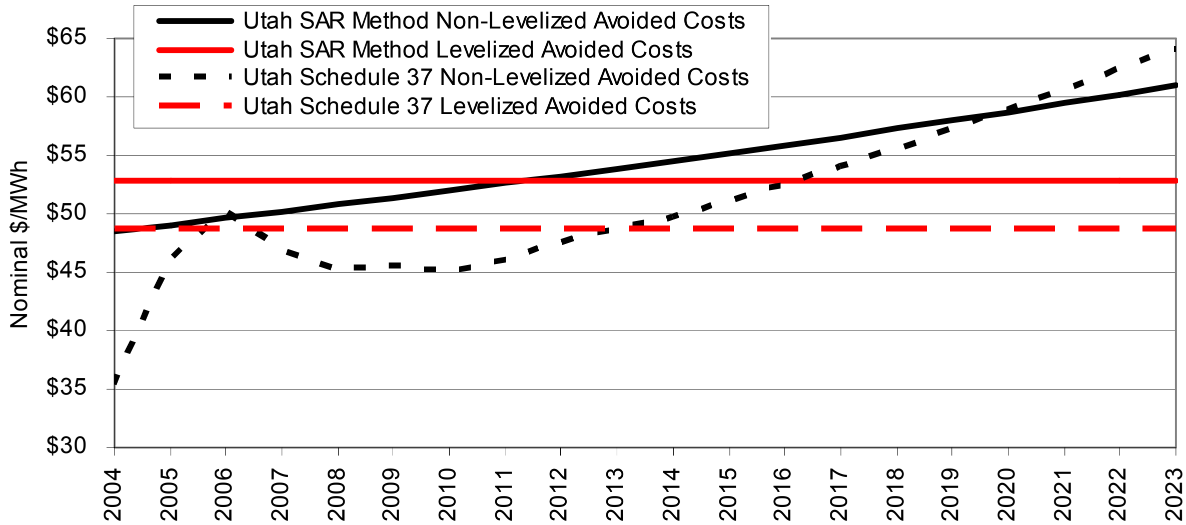

Figure 2. SAR and Schedule 37 Avoided Costs for Non-Wind QFs Under Common Utah-Specific Assumptions (Pacificorp)

The avoided costs shown in Figures 1 and 2, however, are applicable only to *non-wind* QFs that are either able to earn the full capacity payment under Schedule 37, or that will not be negatively impacted by seasonal weighting of the published price under the SAR method. Under both methods, *wind* QFs will earn avoided costs that are lower than those shown in Figures 1 and 2. Specifically, wind QFs opting for the "capacity and average energy payment" pricing option (i.e., the pricing option shown in Figures 1 and 2) under Schedule 37 will only earn 20% of the full capacity payment, while – based on recent experience in Idaho (discussed later and depicted in Figure 5) – a wind QF under the SAR method will likely earn about $1.15/MWh less on a levelized basis due to seasonal weighting of the published price.

Figure 3 shows the impact of these two mechanisms used to de-rate the capacity value of variable wind generation. As mentioned above, based on recent experience in Idaho, we assume that the seasonal weighting of the SAR method will reduce the levelized price by about $1.15/MWh to $51.7/MWh. More significantly, the reduced 20% capacity payment lowers the Schedule 37 levelized avoided costs by about $10/MWh to $38.65/MWh. Thus, for a wind QF, the Schedule 37 levelized avoided cost is about **$13/MWh below** the seasonal-weighted SAR method using Utah-specific assumptions (and is about **$19/MWh below** the seasonal-weighted SAR method using Idaho-specific assumptions).

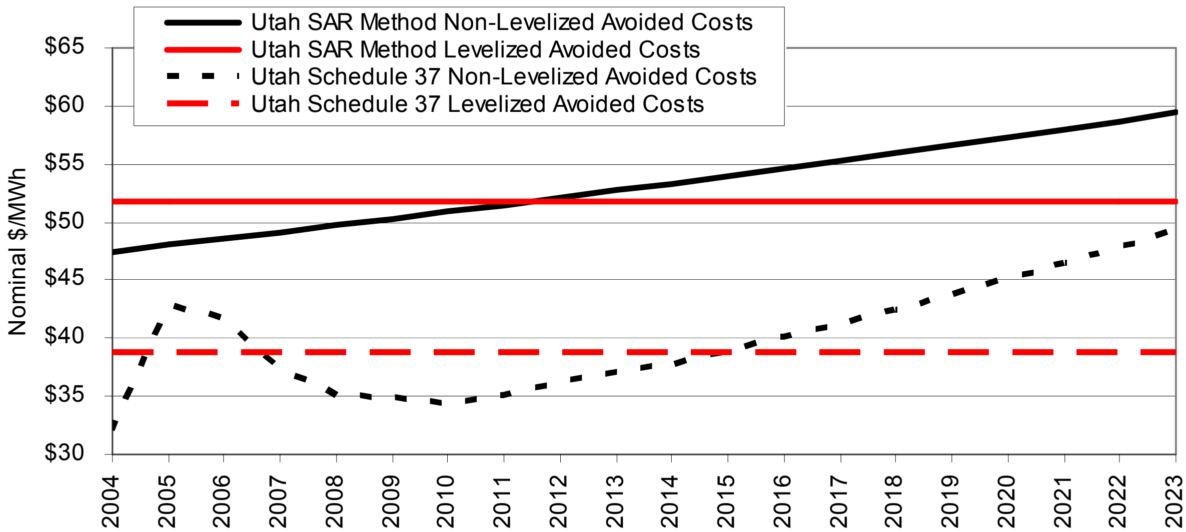

Figure 3. SAR and Schedule 37 Avoided Costs for Wind QFs Under Common Utah-Specific Assumptions (Pacificorp)

In summary, the difference in levelized avoided cost received by a wind QF in Idaho and Utah can be broken down as follows: ~$5.75/MWh due to differences in input assumptions (e.g., fuel price projections, capital carrying charges, proxy plant cost and performance characteristics); ~$4.25/MWh due to consideration of resource sufficiency/deficiency periods in Utah but not Idaho; and ~$9/MWh due to differences in the capacity value assigned to wind (i.e., wind is de-rated by ~$10/MWh in Utah through reduced capacity payment, and by ~$1/MWh in Idaho through seasonal weighting of the published price). Hence, capacity value considerations account for *nearly half* of the overall difference in avoided costs for wind QFs in Idaho and Utah, with the remainder split more or less evenly between other methodological differences and varying input assumptions.

One could question whether the 20% capacity value ascribed in Utah is too low. Indeed, in the July 20, 2004 Order on Reconsideration in Docket No. 03-035-T10, the Utah PSC notes that Pacificorp has stated that the seasonal- and time-differentiated pricing option provides wind generators operating at a 30% capacity factor with a partial capacity payment equal to about 35% of the full capacity value embedded in the seasonal- and time-differentiated prices. In other words, wind operating at a 30% capacity factor effectively earns about 35% of the implicit capacity value paid to the proxy plant assumed to be operating at an 85% capacity factor (i.e., 30%/85%=35%). In comparison to the ~35% capacity value that a wind QF would apparently implicitly receive if opting for the time-differentiated pricing option, the 20% capacity value explicitly assigned to wind under the "capacity and average energy payment" pricing option appears to be low.

Furthermore, a comparison of the "capacity and average energy payment" schedule (assuming 20% capacity value for wind) to the alternative of seasonal on- and off-peak pricing also available under Schedule 37 also suggests that the 20% capacity value assigned to wind may be too low. Figure 4 shows that, assuming 20% capacity value for wind, the "capacity and average energy payment" schedule is only slightly higher than the stream of *off-peak* energy payments available under Schedule 37.[2] In fact, if a wind QF in Utah expects as little as 10% of its annual generation to be on-peak, it will still be better off choosing the time-differentiated payment schedule as opposed to the "average energy and capacity" schedule. Since, in Utah, Pacificorp considers 56% of all hours to be on-peak,[3] and because a wind project with a 30% capacity factor might actually be generating at least some energy (though not necessarily peak output) in 70%-80% of all hours, choosing the time-differentiated peak/off-peak pricing option appears to be a good bet. This bias towards the time-differentiated pricing option can perhaps be interpreted as an indication that the 20% capacity value used in the "capacity and average energy payment" pricing option is too low.[4]

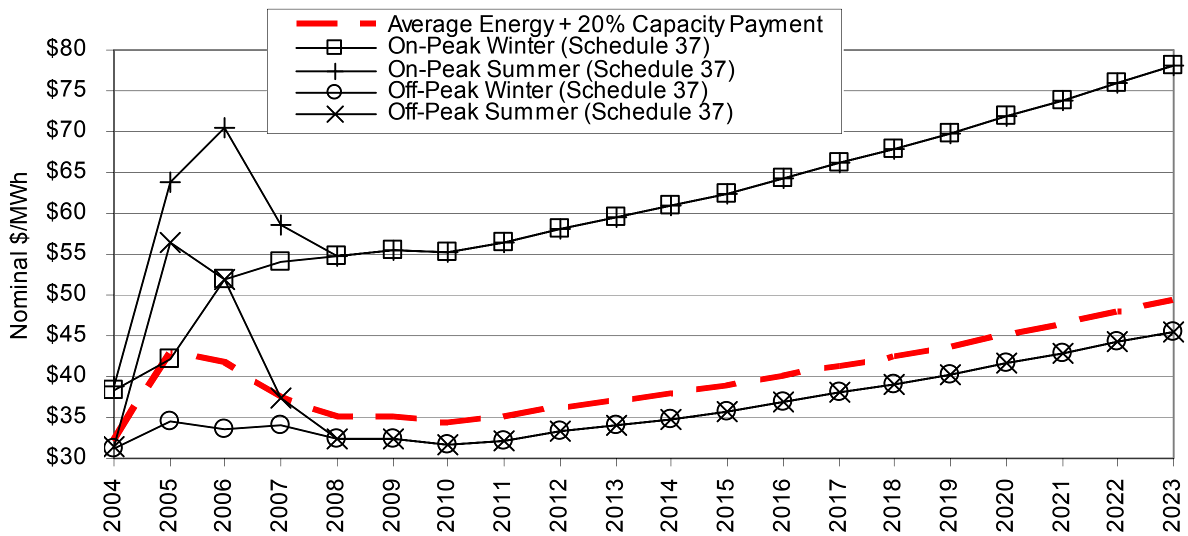

Figure 4. Comparison of Both Pricing Options Available to Wind QFs Under Schedule 37

Pacificorp Objections to the SAR Method

In Oregon, Docket UM 1129 is currently investigating various aspects of avoided costs and QF contracts. As part of that proceeding, various parties have discussed the appropriateness of the SAR method. Below I quote and paraphrase Pacificorp's primary objections to the use of the SAR method in Oregon, as contained in the testimony of Mark Widmer (Pacificorp), starting on

[2] Note that seasonal differences between on- and off-peak prices only persist through 2007; after that, there is a single on-peak and off-peak price applied throughout the year, regardless of season.
[3] In Utah, the percentage break-down between on- and off-peak hours is as follows: 37% winter on-peak, 19% summer on-peak, 29% winter off-peak, 15% summer off-peak. Thus, 67% of all hours are considered to be winter and 33% are summer, while 56% of all hours are considered to be peak and 44% are off-peak.
[4] Given that a wind QF in Utah would likely be better off choosing the seasonal- and time-differentiated pricing option, one might reasonably question why we have instead depicted the "capacity and average energy" pricing option in Figures 1-3. We did this because in order to have shown the seasonal- and time-differentiated pricing option in Figures 1-3, we would have had to make various assumptions about the seasonal and diurnal generation profile of both wind and non-wind QFs in Utah. While do-able, such assumptions would have introduced a degree of uncertainty into the analysis that we preferred to avoid (and note that for the same reason – a preference for certainty over uncertainty – a wind QF may prefer the "capacity and average energy payment" pricing option, all else equal).

page 20 of http://www.pacificorp.com/Regulatory_Testimony/Regulatory_Testimony42622.pdf). Following each objection, I discuss the reasonableness of each objection and, where possible, present counter-arguments.

Pacificorp Objection #1: "The SAR methodology produces a single $/MWh price that applies to all QF generation regardless of season or time of day." Thus, the SAR method allocates some capacity benefits in all hours and does not differentiate between peak and off-peak hours. This does not provide an incentive for QF's to deliver during peak hours. In Docket N. 03-035-T10, the Utah Commission adopted peak and off-peak pricing (which is consistent with the current method – up for revision – in Oregon).

Discussion: With respect to Objection #1, the Idaho PUC has allowed the avoided cost payment determined by the SAR method to be weighted seasonally, such that the weighted average of all seasons equals the published avoided costs (assuming steady output from the QF throughout the year). For example, the Idaho PUC recently approved a QF contract between the Fossil Gulch wind project and Idaho Power. Page 7-9 of that contract (see http://www.puc.state.id.us/fileroom/electric/ipc-e-04-19/app.pdf) lists the base price, the "seasonalization factors" applied, and the amount of wind generation projected to be delivered in each season. Idaho Power will pay Fossil Gulch 73.5% of the published avoided cost in Season 1 (March, April, May), 120% of the published avoided cost in Season 2 (July, August, November, December), and 100% of the published avoided cost in Season 3 (June, September, October, January, February). If the wind QF generated the same amount of power in each month of the year, the weighted-average price it received would equal the published avoided cost. Because of seasonal variation in the wind profile, however, Fossil Gulch can expect to receive a weighted average price that is about $1.25/MWh below the published avoided cost on average ($1.15/MWh less on a levelized basis). Figure 5 shows the impact of "seasonalization" on Fossil Gulch's projected price.

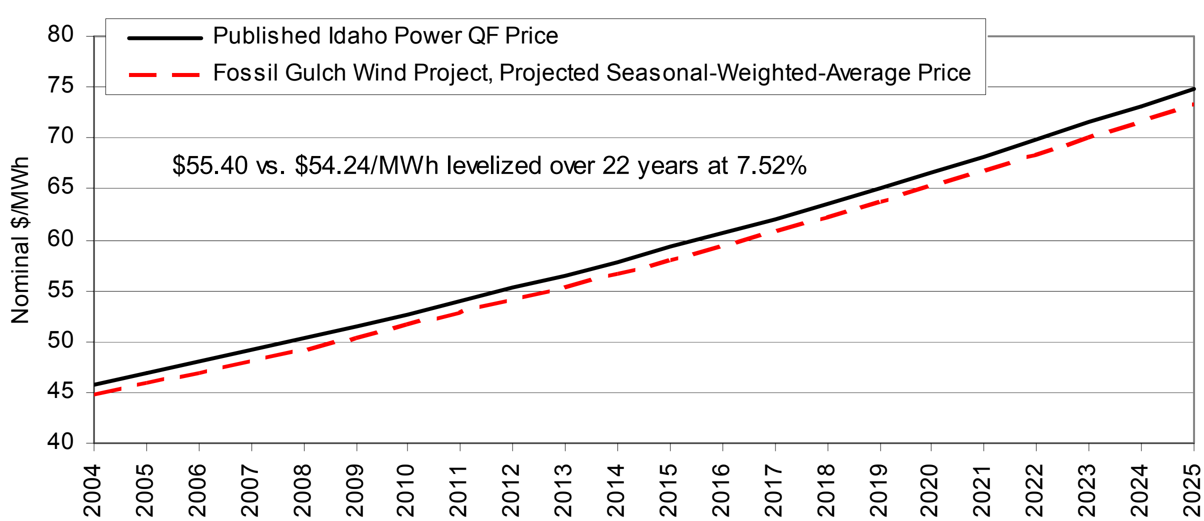

Figure 5. Impact of Applying "Seasonalization Factors" to Idaho's Published Avoided Costs

This example of a real-life application of the SAR method in Idaho counters, at least with respect to seasonal variations, Pacificorp's contention that the SAR method applies a single price "regardless of season or time of day." There also does not appear to be any reason why the SAR published avoided cost could not be further dissected into peak and off-peak periods.

In addition, QF's in Utah already have the option to be paid either a "capacity and average energy" price – which does not differentiate between peak and off-peak periods – or alternatively seasonal peak/off-peak pricing. Furthermore, after 2007, the seasonal pricing in Schedule 37 is no different for winter or summer anyway (though peak and off-peak prices do differ). As such, this argument against the SAR method is not as effective in Utah – where a non-time-differentiated pricing option already exists under the "average energy and capacity payment" option – as it might be in Idaho or Oregon.

Finally, it perhaps deserves note that the Idaho PUC recently approved a measure that will penalize QFs that fail to deliver energy within a range of 90% to 110% of their forecasted output over the course of a month. This measure strengthens the incentive – already present within the SAR method of calculating avoided costs – for QFs to deliver power as projected.

Pacificorp Objection #2: "The SAR method fails to accurately calculate capacity and energy." The SAR method is based solely on the capital and O&M costs of a proxy combined cycle combustion turbine (CCCT). However, the least-cost avoided source of capacity is a simple cycle combustion turbine (SCCT). Pacificorp argues that the capacity component of avoided costs should therefore be based on the fixed costs of a SCCT, not a CCCT. A SCCT is less efficient than a CCCT, however, which results in higher energy costs. Pacificorp acknowledges that this extra energy cost should be included in the energy component of avoided costs as a "capitalized energy adjustment." In other words, relying solely on a CCCT to calculate avoided capacity and energy costs will overstate the capacity payment and understate the energy payment; Pacificorp proposes to solve this problem by using a SCCT for capacity payments, and a modified CCCT (modified such that energy costs are higher) for energy payments.

Discussion: Pacificorp's Objection #2 is not really arguable – i.e., Pacificorp is correct that the SAR method does not accurately calculate capacity and energy payments (in fact, the SAR method does not even attempt to split avoided costs into these components). However, Pacificorp's objection presupposes that a methodology that splits avoided costs into capacity and energy payments is superior to all others. This does not appear to be a foregone conclusion in Utah, where one of the pricing options agreed to under Schedule 37 (i.e., the time-differentiated option) does *not* explicitly split out capacity and energy payments. Pacificorp appears to be accepting of the Schedule 37 time-differentiated option, and as noted above under the discussion of Objection #1, there does not appear to be any reason that avoided costs calculated under the SAR methodology could not be seasonally (as they are in Idaho) or diurnally weighted to arrive at a time-differentiated price that favors on-peak generation.

Pacificorp Objection #3: "The SAR method includes a fixed price escalator for gas prices that is not adjusted to track changes in gas supply and demand. It assumes that gas prices will start at a current gas price and escalate at a fixed rate thereafter." This could lead to an overpayment to QF's if gas prices increase at less than the assumed escalation rate.

Discussion: With respect Objection #3, it should be noted that in Idaho, both the starting gas price and the fixed escalation rate applied to it over time are derived from the NWPPC's natural gas price forecast (basis East-Side Delivered). Moreover, the Idaho PUC has found (in Order No. 29124) that avoided costs should be updated each time the NWPPC issues a new gas price forecast. As such, this methodology is not quite as primitive or baseless as Pacificorp's comments imply. Since any attempt to calculate future avoided costs will necessitate making assumptions about future natural gas prices, this issue really boils down to which forecast or gas price projection to use. In Idaho, they use a modified (simplified) form of the NWPPC gas price forecast. In Utah, they use an average of two parties' (Pacificorp's and the consumer advocate's) forecasts. It is impossible to say whether either of these forecasts is "better" than the other. We at LBNL have argued that in fact, utilities should be using forward prices – not price forecasts – in instances such as this, and have found over the past five years that forward prices have generally exceeded most price forecasts (implying that avoided costs would have been higher if forwards had been used instead of forecasts).[5] This is an important issue that *all* avoided cost methods must deal with – i.e., the SAR method cannot be singled out on account of its fuel price forecast.

Pacificorp Objection #4: "The SAR method, as recently modified by the Idaho Commission, no longer considers the utility resource surplus period. Effectively, the modified method assumes that there is no surplus period and that the utility needs additional resources immediately. This can result in additional subsidy in that avoided costs will reflect a capacity payment in periods of sufficiency when the QF purchases are not actually avoiding capacity additions."

Discussion: Pacificorp is correct in Objection #4 – i.e., the SAR method as practiced in Idaho does not consider resource sufficiency/deficiency periods. Also note that PGE's testimony in UM 1129 (Oregon PURPA/QF proceeding, see http://www.portlandgeneral.com/about_pge/regulatory_affairs/filings/pdfs/UM1129/kuns_drennan_testimony.pdf) also criticizes the SAR method on these grounds (i.e., that it assumes that utilities are always capacity-deficient). Specifically, PGE states that ignoring the resource sufficiency period is inconsistent with least-cost planning, and that the SAR approach (as modified in Idaho) effectively replaces the utility resource planning process with a separate plan.

While the utilities have a point, it is nevertheless still possible to dispute the benefits of considering resource sufficiency/deficiency periods in the first place. For example, on September 26, 2002, the Idaho PUC issued Order No. 29124 (see http://www.puc.state.id.us/search/orders/dtsearch.html, type in 29124), which modified the

[5] See, for example, http://eetd.lbl.gov/ea/ems/reports/54751.pdf.

existing avoided cost methodology and established the methodology in use today. One of the primary modifications was to abolish consideration of resource sufficiency/deficiency periods. In arguing for abolishment, Commission Staff presented nine reasons (quoted verbatim here):

1) "Establishment of utilities' first deficit years requires regular filings by the utilities followed by Commission Orders. None of the utilities have made a filing to update its first deficit year since the first deficit years were last established in 1996.
2) It is unclear whether determination of a first deficit year should be based on a utility's energy needs or capacity needs.
3) When a utility becomes deficit depends on the conditions assumed for planning. Water conditions and reserve margins used for planning are not consistent for all of the utilities.
4) Load forecasts are one half of the surplus/deficit equation. Load forecasts are prepared entirely by each utility with little or no oversight. Utilities can easily manipulate their load forecasts to produce a desired result.
5) Utilities increasingly rely on market purchases. Should long-term contracts that do not begin for several years be counted as resources in determining first deficit year?
6) The difference between "surplus" energy rates and "SAR-based" rates is not as great as it used to be; therefore, there is less justification for two different bases for parts of the avoided cost computations.
7) Utilities always plan to be surplus in the short-term, at least for as long as it takes to acquire new resources. Having too large of surplus can be as problematic as being deficit. Avoided cost rates should not provide incentives for a utility to increase its surplus period.
8) The addition of a PURPA project, particularly if it is less than 10 MW, does not have a large impact on a utility's load-resource balance. The cumulative effect of many PURPA projects could have a significant impact, but the capacity of PURPA projects has historically been small.
9) If surplus energy rates are retained in the avoided cost analysis, determination of the prices to be used during a utility's surplus period poses some difficulty because of recent extreme variations in market prices."

In general (along the same lines as the seventh comment listed above), it seems that if a utility perpetually believes that it is currently in a period of resource sufficiency (as it presumably must if it is able to reliably serve its customers), then it might never consider the construction of a CCCT (the proxy plant) to be economical – i.e., it might always be economically advantageous to postpone the construction or acquisition of such a resource. Obviously, such a situation cannot persist indefinitely without the utility eventually getting into trouble with respect to resource needs. As long as (or if) it does, however, QF's will be at a disadvantage. This is perhaps more of a general observation than a specific argument against consideration of resource sufficiency/deficiency periods.

In summary, while Pacificorp's four main objections to the SAR method are in some cases accurate and persuasive, none of them represent a "silver bullet" against the SAR method, and all four of them can be argued, in some cases just as persuasively. Again, though, given the relative breakdown in avoided cost differences between Utah and Idaho (~$5.75/MWh due to varying input assumptions, ~$4.25/MWh due to resource sufficiency considerations, and ~$9/MWh due to different methods of de-rating wind's capacity value), simply arguing for one method over another may not be as fruitful as focusing on those specific assumptions or methodological elements that could potentially be adjusted to increase avoided costs paid to wind QFs in Utah.

Based on the analysis above, those assumptions or methodological elements that seem most "vulnerable" in Utah include:

- **Wind's Capacity Value:** As discussed above, something higher than 20%, and perhaps as high as 35%, may be warranted.
- **Fuel Price Projections:** As noted above, the current natural gas price forecast used in Schedule 37 shows gas prices in real or constant dollars *declining* on an average annual basis over the forecast period. Such a projection is clearly open to criticism and potential upward revision.
- **Capital Carrying Charge:** As shown earlier in Table 1, there is a sizable difference between the capital carrying charge used in Utah (8.71%) versus Idaho (12.60%). In a nutshell, the capital carrying charge is used to "spread out" the full capital cost of the proxy plant into a levelized annual cost. In other words, in Utah, each year 8.71% of the total proxy plant cost contributes to that year's avoided costs. In Idaho, each year 12.60% of the surrogate plant cost contributes to that year's avoided costs. Thus, in Idaho, a significantly larger percentage of the proxy plant's cost is being included in avoided costs each year than is the case in Utah, leading to higher avoided costs. Recall, however, that Idaho employs a "tilting rate" that reduces the amount of capital costs recovered through the QF contract – this will serve to mitigate somewhat the impact of a higher capital carrying charge.[6] Even so, it might be worth investigating why capital carrying charges differ so much between Idaho and Utah (for the same utility, no less).
- **Resource Deficiency Periods:** Some of the arguments used by Idaho PUC staffers to justify the abolishment of resource sufficiency/deficiency considerations may find traction in Utah.

Other Potential Considerations

In addition to tinkering with or arguing for certain avoided cost methodologies or avoided cost input assumptions, the Utah Wind Working Group may wish to consider pursuing two other possible sources of revenue: renewable energy credits and carbon credits.

- **Renewable Energy Credits (RECs):** Recently, the FERC ruled that unless a QF contract explicitly allocates ownership of renewable energy credits (RECs) to the utility, the RECs remain the property of the QF. In Idaho, the PUC has also ruled that RECs stay with the QF. In Utah, this issue is apparently under study by a task force that was expected to report its

[6] For example, it was noted above that the tilting rate leads to only 82% of the capital cost of the surrogate plant being recovered through the QF contract. Since 82% of 12.60% equals 10.3%, perhaps 10.3% is effectively the "correct" capital carrying charge to use when making comparisons with Utah. Additional investigation and analysis would be needed to clarify this, however.

findings at the end of 2004. If not transferred to the utility or its ratepayers, RECs could provide an additional source of revenue to QFs in Utah. Alternatively, if the Utah PSC ultimately rules that RECs are transferred to the utility or its ratepayers through a QF contract, this could provide grounds for QFs to negotiate a higher avoided cost rate.

- **Carbon Risk:** Pacificorp has explicitly modeled and accounted for the risk of future carbon regulations in its IRP process. Given that the utility has acknowledged and incorporated carbon risk into its resource planning process, it may be possible for non-carbon QFs to extract some incremental value in exchange for their ability to mitigate carbon risk. While I am not aware of any direct precedent for such a measure, it is perhaps noteworthy that in December 2004, the California Public Utilities Commission issued an order requiring the state's IOU's to incorporate a "greenhouse gas adder" into the bid price of fossil-fueled resources when evaluating bids from long-term, all-source solicitations. Specifically, the utilities must add between \$8-\$25/ton of CO_2 (equates to approximately \$3-\$9/MWh for a CCCT) to the bid price of fossil-fueled resources, for evaluation purposes only (the GHG adder will *not* impact the price paid to the winning bidders). Xcel Energy is another utility that has incorporated externality values into its bid evaluation process for all-source solicitations. In other words, consideration of carbon risk is currently affecting resource decisions and favoring carbon-free resources in utility solicitations. Given this reality, it does not seem entirely unreasonable to seek QF pricing that also differentially favors carbon-free resources such as wind power.