Corrections to the Benefits/Costs Study for RTO West

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Tabors Caramanis & Associates has produced the "final" report, RTO West Benefit/Cost Study. One component of the study is an analysis of potential reduced congestion costs and generation savings in the Western Systems Coordinating Council (WSCC) area due to formation of RTO West. We believe that the TCA Study, commissioned by the RTO West Filing Utilities, can be misinterpreted. As corrected, the value of RTO West over the entire Western Systems Coordinating Council (WSCC) area could be only $49 million instead of $410 million per year.[1] The Filing Utilities have declared that they intend that no corrections be made to the study's results despite the problems we continue to see in the analysis. Further analysis of these issues could provide a better estimate of the potential costs or benefits of RTO West.

The TCA estimate of generation and congestion savings is distorted in two principal ways:

- The model assumes, in its Without RTO base case, that Pacific Northwest and other West-coast utilities are making irrational, costly operational decisions today that those utilities are not, in fact, making. The result is to overstate the cost of today's system and thereby make the RTO option look better.
- Nearly half of the benefits estimated for the RTO—the so-called Congestion Rents—are not a result of cost reductions but of a shift of who pays for the transmission of power.

The study uses assumptions and modeling techniques that overstate the potential benefits of RTO West, and derive from a misinterpretation of the study results. As participants in the Cost Benefit working group, we are compelled to provide the following analysis.

RTO West Study Results as Presented and With Corrections

	Avoided Congestion Rents	Generation Savings	Total Benefits
WSCC area by TCA[2]	$171 Million	$239 Million	$410 Million
WSCC area with corrections	$ 2 Million	$47 Million	**$49 Million**

[1] As a very rough approximation for the RTO West area alone, using the same ratio of RTO to the total West benefits as calculated in the initial study, the RTO West benefits would be $36 million instead of $305 million.

[2] The analysis uses the West-wide changes for a specific reason. Using just the RTO West-area results introduces an unnecessary complication in interpretation, because the With RTO case includes significantly higher exports of power to British Columbia and California. As a consequence of the increased exports, there is actually a generation-cost increase in the RTO West area in the With RTO case, making it appear that creation of RTO West brings no benefit in terms of generation savings. That conclusion is wrong and is more confusing than illuminating. Use of the WSCC-wide results more clearly demonstrates the impact of the corrections.

The following corrections were made to the model to obtain a more realistic view of the potential transmission and power benefits of RTO West.[3] These results must be considered in the context of other potential benefits and costs, including the operating costs of the entity, the substantial risks that still remain, including the exercise of market power and localized impacts on specific utilities or subregions within the Northwest.

∑ **The Without RTO Base Case should assume current practice for scheduling generation-plant maintenance rather than assuming fundamentally irrational behavior by West-coast utilities. The result of this change: Power cost benefits attributable to RTO West are reduced by approximately $27 million.**

Northwest utilities schedule the maintenance of their generation facilities in order to take advantage of opportunities in power markets for what are called "economy" purchase and sales, while also meeting their obligations to serve. The highest-price market opportunities generally occur in August on the West Coast. Expected revenues from those sales are used to reduce power rates for native-load customers.

The Without RTO base case assumes that utilities schedule their maintenance with no regard to market opportunities. The result is exemplified by the maintenance schedule for WNP-2, which the model calculates would occur in August, the best time of the year to have extra power to sell and the worst time of the year to schedule maintenance. The Without RTO assumption does not reflect reality. Scheduling maintenance the same way in both cases, as might be expected when utilities look at market opportunities, reduces generation costs savings due to RTO West by $27 million, according to TCA's own sensitivity study. (TCA Study, Maintenance Schedule sensitivity, pages 34)

∑ **The Without RTO Base Case should reflect the fact that Northwest utilities actually provide operating reserves from the hydro system today rather than from costly thermal plants. Change in generation cost savings due to RTO West: minus $150 million.**

For reliability, any power system requires that some generation capability be kept in reserve ("spinning reserves"). In the Northwest today, these spinning reserves are provided almost entirely by hydro generation units, because there is no fuel cost to having them available and because hydro units are often most efficient when they are not operated at full capability. As a result, spinning reserves are available today and in the near future in the Northwest at virtually no incremental cost. Nearly all the Northwest utilities use the hydro system to provide their reserves today. That fact should have been reflected in the Without RTO base case.

It was not. The Without RTO case does not mirror reality. TCA made two unrealistic assumptions. First, the study assumed that the investor-owned utility shares of Columbia River hydro projects were not available to meet their spinning reserve requirements. (Source: Teleconference with TCA.) Second, the study also used only a portion of the (unloaded) hydro that was available for such reserves, forcing

[3] The various corrections, based largely on the TCA report itself, are assumed to be additive. In fact, there may be interactions among them that would modify the results—but probably only slightly. Until the TCA model is run with all of these corrections, the complete result won't be known.

unrealistically high reliance on thermal units for reserves. Treating reserves in the same way in both studies (with and without RTO West) reduces generation costs by $150 million. (TCA Study Operating Reserves Sensitivity, page 34)

∑ **In the With RTO Case, generation costs should be increased to reflect the fact that there will be power losses when the region generates the additional 1000 aMW of exported power that the model says will be produced in and exported from the Northwest. We have calculated the effect on the With RTO generation cost to be about $14 million.**

With an RTO, the TCA model says the Northwest will increase exports of power from its coal and gas-fired plants by 1000 aMW per year. In reality, a generator planning to transmit that additional power to California and British Columbia would have to produce more power than is actually delivered in order to account for real power losses that occur when power is transmitted anywhere, but, in particular, over long distances. The With RTO case assumed that power is generated without those losses; thus, it understates the generation costs of the With RTO case, making the With RTO result more attractive than it should be.

Adding an estimate of the costs of the losses to the With RTO Case increases generating costs by about $14 million, using the model's assumption of power losses and a $30 / MWh cost of power. This additional cost reduces the overall benefits of RTO West by the same amount.

∑ **Almost 92 percent of the RTO benefit called "Congestion Rents" derive from shifting the responsibility for the costs of transmission losses from power prices in the Without RTO case to some other cost-recovery mechanism. This cost shift cannot be counted as a "benefit" in the With RTO Case, because these costs still must be paid by consumers. The costs do not go away as the model appears to show. Accounting for these costs reduces congestion rents and the alleged benefits of RTO West by $157 million.**

In the With RTO scenario, costs that are currently paid by consumers through one line item on their electricity bill—energy—would, in effect, be shifted to a different line item on the bill—transmission. The cost/benefits study incorrectly attributes as a benefit the change in <u>how</u> costs are paid, making no allowance for the fact that the end users still must pay those fixed costs one way or the other.

A TCA sensitivity case can be used to correct for this problem. The study estimates the difference in congestion rents assuming that losses are treated the same way in both the With and Without RTO cases. That sensitivity case indicates that avoided congestion rents fall by $157 million. Thus, the treatment of losses accounts for 92 percent of the benefit labeled "avoided congestion costs." (TCA Study, Transmission Line Losses sensitivity, page 30) That is, the benefits of RTO West are overstated by $157 million annually. It is misleading to regional decision makers to attribute these cost shifts as benefits of RTO West.

∑ **The RTO Case incorrectly and inconsistently treats certain transactions that cross control-area boundaries. Removing the inconsistency and treating the transactions correctly will result in a $1 million savings in generation costs and a $12 million**

savings in Congestion Rents.

In the Without RTO case, tariffs and loss charges generally are assigned to transactions that cross control area (usually utility) boundaries and not to transactions that take place within a control area. For example, in the model there are no transmission charges assigned to a transaction where a PGE resource in the PGE control area goes to a load in the same control area. However, when a resource in the PacifiCorp control area moves to a PGE destination, that transaction would be charged the PacifiCorp transmission tariff and loss charges, and there would be no additional charges once the power was delivered to the PGE system. Given the way the model analysis is designed, it is equally appropriate either to charge for transactions entirely within a control area or not to charge for them at all, as was done for most utilities in this study. (In the latter case, they would be accounted for in Company Rate charges.)

What is not appropriate is to treat BPA and the Imperial Irrigation District (IID) differently from the rest of the utilities in the WSCC. For those two utilities, a second level of tariff and loss charges is applied to a transaction that starts outside the BPA (or IID) control area and ends up at a BPA (or IID) load. The second level of tariffs is not charged when other transactions cross two control areas. Such a modeling treatment is inconsistent and is incorrect. The result is to make the Without RTO results more costly, and therefore the existence of an RTO more favorable. (The inconsistent treatment is noted at page 9 of the study and is footnoted on that page.)

The corrections come from the March 5, 2002, version of the study (footnote, page 9) contains the estimated amount of this error, which is $1 million for generation costs and $12 million in Congestion Rents. Though that version was withdrawn, the adjustments are assumed to remain valid.

∑ **The remaining generation-cost savings are a high or generous estimate of the generation benefits—reduced fuel costs--of forming an RTO.**

There are two factors that suggest that the benefits that are measured are generous and represent the high range of value to the RTO.

First, the TCA model assumes that all transactions are completed at what are called Locational Marginal Prices (LMP). This LMP measure approximates the spot market price at each pricing point or node in the WSCC. In the Without RTO case, the model calculates an LMP that assumes that all *power* transactions face a *transmission* charge that is based on kilowatt hours transmitted. All transactions have to recoup sum of their (per-kWh) transmission and generation costs in order for the resource to operate.

In reality, many transmission contracts specify long-term payments that do not vary with the amount of power produced and transmitted. These contracts are based on annual payments or contract charges that must be made whether or not power is actually transmitted. Because of the fixed-cost nature of these transmission contracts, the marginal cost of transmitting another MWh of power is zero (except for losses), the same as in the With RTO case. As a consequence, the kWh charge attached by the TCA model to each and every marginal transaction in the Without RTO case is too high, and the resulting operation of the plant is inefficient. From a societal benefit point of view, there should be no significant difference in the With and Without RTO results of plants using

fixed-price transmission contracts.

These existing transmission contracts do not impede economic efficiency despite the fact that the Without RTO model analysis shows that they do. There would be no generation-cost savings associated with units that rely on long-term transmission contracts despite the TCA analysis calculation to the contrary. The TCA results do not, and, without considerable effort, cannot take into account the extent of fixed-price transmission contracts. Almost all the contracts that connect distant generation resources to loads, such as Colstrip, are of this sort.

There is a second reason that the final result may overstate the benefits of RTO West. Because of limitations of the TCA model in representing the hydro system, it is likely that it does not recognize the immense flexibility of the hydro system in any of its base or sensitivity cases. As a result, the TCA modeling could not reflect the full benefits of the hydro system.

Indeed, a more accurate representation of the hydro system would show less benefit due to formation of the RTO, because many of the benefits the TCA model attributes to the RTO in the model are achieved in both cases.

As a consequence of fixed-price transmission contracts and the hydro flexibility that is not measured, the $49 million in benefits should be considered at the top of the range of benefits.

The following table provides a summary of the corrections discussed above:

Summary of Corrections

	Avoided Congestion Rents	Generation Savings	Total Benefits
TCA Result	$171 Million	$239 Million	$410 Million / year
Correcting scheduled maintenance		($27 Million)	($27 Million)
Recognizing hydro is used to produce NW spinning reserves		($150 Million)	($150 Million)
Providing losses for increased exports		($14 Million)	($14 Million)
Recognizing that losses must still be paid	($157 Million)		($157 Million)
Using consistent rules for transactions among utilities	($12 Million)	($1 Million)	($13 Million)
Corrected Result	$ 2 Million	$47 Million	**$49 Million / year**