REVENUE SUFFICIENCY GUARANTEES, COST CAUSATION, AND COST ALLOCATION

William W. Hogan[i]

October 9, 2008

Introduction

These comments supplement my earlier submission regarding the Revenue Sufficiency Guarantee (RSG) and associated analyses of cost causation and cost allocation under the Midwest Independent System Operator (MISO) tariff. [1] In an early order, the Federal Energy Regulatory Commission (FERC) cited my previous submission in part to support a conclusion that in the MISO day-ahead market, virtual offers and bids could affect commitment and dispatch total costs and the total RSG payments.[2] In this supplement my purpose is to extend the analysis to address further the issues of cost causation and the interaction of virtual offers with other features of the MISO electricity markets.

The cost causation argument has been converted to a focus on deviations of real-time dispatch relative to day-ahead schedules. This focus on deviations is misplaced, and the fundamental principles of cost causation have not been followed in developing procedures for RSG payment allocation. Furthermore, the impact of energy pricing rules and the nature of the commitment process have not been addressed in a way that would be necessary to apply the principles of cost causation. My earlier submission touched on many of these issues, and is attached in order to avoid the necessity to repeat all the arguments. Examination of the interaction among energy pricing procedures, unit commitment logic, and virtual offers illustrates how these may affect costs. The connection is complicated and cost causation principles applied to virtual offers do not provide much guidance for the allocation of RSG payments. The alternative principle of allocating residual total costs to relatively inelastic total load provides a mechanism that would not violate the principles of cost causation and would minimize further impacts on economic efficiency.

Cost Causation Principles

The Commission seeks to follow cost causation principles in assigning RSG payments to market participants. The basic idea is summarized in a filing by Ameren:

> “Fundamental principles of rate design and, particularly, principles of good market design for efficient, organized markets for the sale and purchase of electric energy at wholesale, require that allocation of costs follow causation of such costs as closely as possible. This alignment of cost allocation with cost causation promotes economically efficient

---

1 See Appendix A.

2 Federal Energy Regulation Commission, “Order on Rehearing,” Docket No. ER04-691-074, October 26, 2006, ¶112.

production, consumption and investment decisions by sending clear price signals."[3]

The emphasis on economic efficiency promoted by a clear price signal is an important element of this formulation. This connection to efficiency provides guidance on the nature of cost causation and the implication for cost allocation. Although this is not a counsel of perfection, the basic idea is to draw a logical connection between the actions that cause costs to be incurred and the incentives provided by the allocation of costs. An important feature of this principle is to focus on incremental or marginal costs of an action as distinct from the average cost of a collection of decisions. The marginal cost, not average cost, is relevant to decisions and support of economic efficiency.

The case of the locational marginal price (LMP) for energy and losses provides a good illustration. The total cost to meet load and losses is the summation of all the generation costs. While it is true that total load "causes" these total costs, the price implied is not the average of the costs over all load but the marginal effects of generation, congestion and losses needed to meet an increment of load at a location. If the system is sufficiently well-behaved, this LMP is well defined and provides the right incentives for generation and load. The definition of the LMP is the change in the total system dispatch cost needed to meet the increment of load assuming optimal redispatch of the entire system. The focus is on the marginal change in the total cost. Typically the revenues collected exceed the total cost, with the surplus being the congestion rent and the rent on the difference between marginal and average losses. The excess is treated separately, principally to fund payment obligations for financial transmission rights (FTR).

In order to provide the right incentives and support efficient decisions, cost causation analysis of virtual bids and offers should follow a similar set of principles. The focus should be on marginal or incremental effects, not on the average cost impacts of all decisions. And the relevant cost is the total cost, not just some component of cost. Hence, any focus that addresses RSG payments alone without considering the impact on total costs would necessarily be inconsistent with the basic objectives of cost allocation according to cost causation. Furthermore, proposals that begin with the total RSG payments and attempt to assign them to different buckets miss the point of the cost causation principle. This principle connects incremental decisions to incremental costs. Once the cost causation principle is applied, the resulting allocation may be more or less than the total cost that needs to be addressed, and other principles must be applied to balance the allocation of the total costs. By definition, these other principles must build from something other than cost causation at the margin. Hence, the overall cost allocation scheme requires a mixture of principles.

The objections to an analysis of cost causation argue that ambiguities in the connections that underlay cost causation allow great latitude in choosing a reasonable allocation method. For instance, the Ameren submission argues further that:

---

[3] Ameren Services Company, "Complainants' Brief of Ameren Services Company and Northern Indiana Public Service Company," Docket Nos. EL07-86-000, EL07-88-000, EL07-92-000, Federal Energy Regulatory Commission, September 22, 2008, p. 2.

> "Not surprisingly, though, there are market participants who prefer the status quo with respect to RSG cost allocation, because it is profitable for them. These market participants can be expected to oppose the new RSG cost allocation methodology, and are likely to claim that it does not perfectly link RSG cost allocation to RSG cost causation. As the Commission often has held, however, ratemaking is not an exact science and the Commission may approve a rate that is within the zone of reasonableness; the Commission is not limited solely to the best possible rates."[4]

While it is true that the Commission is not limited solely to the best possible rates, it is not true that there should be no consideration of the structure of cost causation and the role of virtual offers. However, the cost allocation arguments offered to the Commission do not address the fundamentals. The focus on schedule deviations, the implicit argument that cost causation can serve as the foundation for a complete cost allocation, and appeals to simple correlations without any theory of causation are all symptoms of a disconnect from the principles invoked.

The Commission directed the MISO to perform certain simulations to estimate the size of the connection between virtual offers and the resulting RSG payments.[5] Eventually the MISO responded that it was very difficult to identify the reason that any particular plant was committed in the Reliability Assessment Commitment (RAC): "Midwest ISO asserts that there is no one-to-one correspondence between cleared virtual supply and units committed after the day-ahead."[6] As a result, no simulations were preformed to illustrate the nature and degree of cost causation to attribute to virtual offers. The apparent interpretation of this impasse has been that cost causation must still exist even though it cannot be identified. A better interpretation is that the underlying assumptions about the nature and degree of cost causation are not supported by the fundamentals with respect to cleared virtual offers.

My earlier submission used simple examples to illustrate the fundamentals. An expansion of these examples reinforces that earlier analysis and provides more insight to illustrate why there may be little or no cost causation and efficiency effects that can be attributed to virtual offers. This would lead to a need for other principles to define allocation of RSG payments.

Other Factors Contributing to Cost Causation

My comments are specific to virtual offers and the connection with unit commitment and dispatch. There are other factors that can influence RSG payments such as special reliability rules, or events which may directly lead to dispatch decisions which affect overall RSG payments. For instance, while MISO cannot find a one-to-one

---

4 Ameren, p. 4.

5 Federal Energy Regulation Commission, October 26, 2006, ¶117.

6 Federal Energy Regulatory Commission, "Order Accepting in Part and Rejecting in Part Compliance Filing," Midwest Independent Transmission System Operator, Inc., Dockets No. ER04-691-079, ER04-691-081, Issued March 15, 2007, ¶ 77.

correspondence between virtual offers and units committed after the day-ahead, there will be instances in which specific and discrete unit commitments are found in connection with specific events in the real-time markets such as generator and load trips, unexpected transmission outages, local reliability requirements, interface derates, and so on, which are separate from the focus of the examples considered here. These other impacts on RSG payments have been addressed by others in the FERC proceedings.[7] In these cases, where a close correspondence is achievable, the principles of cost causation could apply.

Virtual Offers and Cost Impacts

My previous submission illustrated why virtual offers are not likely to be a significant factor to increasing total RSG payments. In the situation in which unit commitment and dispatch in the RAC process are substantially similar to those which otherwise would have occurred in the day-ahead market, but for virtual supply offers, there should be no material impact on total cost. As discussed in my previous submission and in the current RSG proceeding,[8] the difference in objective functions for the RAC and day-ahead market may not be material for many market conditions.

Previously, I showed that market design issues could have a strong impact on the total costs and RSG payments that arise in the presence of virtual offers in a hypothetical example considering unit commitment effects. My purpose then, as now, was to demonstrate the role that market design issues can play in determining total costs and RSG payments and separate the effects of virtual offers. Two matters of importance are the rules for determination of energy prices and the criterion for the RAC commitment.

Determination of Energy Prices

The energy price choice can have a significant effect on the RSG payments. In the argument summarized above for LMP, the reference to a well-behaved system producing a clear definition of the price was intended to exclude the case of problems that include discrete unit commitment decisions with start up costs and minimum generation limits. With these discrete decisions and costs, the resulting energy price may not be sufficient to cover the full costs of the unit commitment, and this creates a need for the RSG. An added feature is a certain ambiguity in the definition of the proper LMP and, therefore, the associated RSG.

In my previous discussion I pointed out that one approach to calculating LMP in these cases could create a contradiction that precluded achieving an equilibrium solution and therefore complicated or prevented analysis of the impact of virtual offers. Since that time, there has been further work analyzing these situations to develop alternative approaches to determining the "LMP" in the presence of unit commitment decisions and RSG payments.[9] In particular there are pricing methodologies that can avoid the

---

[7] Affidavit of Andrew Hartshorn on behalf of Edison Mission Group Companies, "Comments of the Edison Mission Group Companies," Docket Nos. EL07-860999, EL07-88-000, EL07-92-000, Federal Energy Regulatory Commission, March 24, 2008, Attachment B, p. 11-12

[8] Affidavit of Andrew Hartshorn, p. 8-10

[9] Paul R. Gribik, William W. Hogan, and Susan L. Pope, "Market-Clearing Electricity Prices and Energy Uplift," Harvard University, December 31, 2007, available at www.whogan.com.

contradiction and provide some further insight into the connections of virtual offers and RSG payments. These pricing methodologies provide support for determining an energy price that supports an equilibrium solution in the simplified examples. More generally, relaxing some of the simplifying assumptions to allow for uncertainty, a similar energy pricing rule could support an equilibrium solution with the day-ahead price equal to the expected real-time price. Either way, the examples discussed below posit alternative possible market-clearing energy prices in the day-ahead market and allow calculation of the impacts of decisions on total costs and RSG payments.

RAC Criterion

In addition to the impact of rules for determination of the energy price, the RAC criterion can have a significant effect on the analysis of cost causation. As explained in detail in the attached earlier submission, the impact of virtual offers operates through the change in the unit commitment in the day-ahead market. Under an idealized RAC commitment process that chooses the same unit commitment as when there are no virtual offers, the virtual offers have no impact on total cost or on aggregate RSG payments. However, the presence of virtual offers can move the RSG from day-ahead to real-time, giving the impression that there is a change in costs.

Under a RAC that is more like the criterion applied in the MISO, virtual offers can have an impact on total costs and RSG payments in addition to moving payments from the day-ahead to the real-time market. But the connections between these elements present difficulties similar to those of unit commitment in defining prices and cost causation. The analysis may say more about the evaluation of the RAC rules than about the appropriate attribution of cost causation to virtual offers.

Simplified Example

To demonstrate these points, consider an example problem that is slightly modified from the previous submission to expand the analysis and provide more transparency in the calculations. As in the previous submission, the simplified analysis ignores network effects, assumes a single dispatch interval, assumes no uncertainty, and hence no risk aversion, assumes perfect information, assumes no limits on the quantity of virtual bids, assumes costless virtual bids, assumes bidders act as price takers, assumes no exercise of market power, and applies a simplified model of commitment, dispatch and pricing. These simplifications strip away everything other than the unit commitment, dispatch and virtual offers to isolate the connections with total cost and RSG payments.

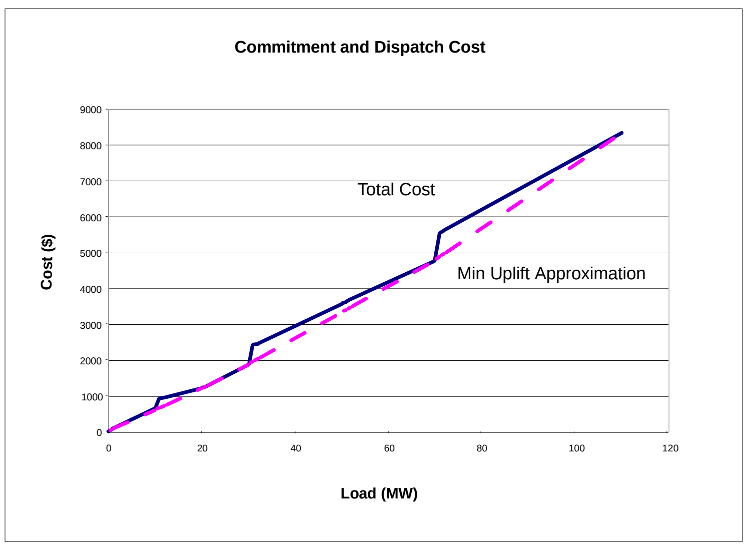
The following table summarizes inputs for a situation with four power plants. The case examined is for a physical load of 45 MW cleared in the day-ahead market and realized in the real-time market.

Plant	Fixed Cost ($)	Plant Configuration Energy ($/MWh)	Capacity (MW)	Average Cost ($/MWh)
A	700	55	40	72.5
B	600	31	20	61
C	699	72	40	89.475
D	0	66	10	66

To keep the example simple, there is no minimum generation level for plants when committed. Additional more realistic features such as minimum generation levels could be incorporated and have more effect on the dispatch, but would not change the essential characteristic of the discrete nature of unit commitment.

At a load of 45 MW, plants B and D alone could not meet the total load. Hence, either plant A or plant C must be included in the final commitment and dispatch. The least-cost solution to meeting demand would be to use plants A and D at 40 and 5 MW, respectively, for a total commitment and dispatch cost of $3230 (=700+40*55+5*66) exclusive of RSG payments.

Given this commitment and dispatch, there is a range of prices that might apply. The marginal cost of $66 for plant D is one natural candidate for the energy price. However, this is a choice which produces a large RSG. Any price higher than $66 would create opportunity costs for the dispatch of plant D but would lower the RSG payment for plant A. In Gribik et al., the combination of these RSG and opportunity costs is defined as an uplift to be paid to compensate for losses and foregone profits. A possible choice for the energy price would balance these elements and seek the minimum uplift. This minimum uplift price can be obtained as the price implied by an approximate cost function that provides the best approximation of the unit commitment and dispatch total cost function. Using the example data, this approximate cost function is shown in the accompanying figure.



By definition this approximate cost function is well-behaved and yields a well-defined LMP price that minimizes the uplift. In the figure the slope of the approximate cost function defines the energy price and the difference between total and approximate cost is the sum of the RSG and opportunity costs at the corresponding energy price. In the present case at a load of 45 MW the minimum uplift price is $72.5/MWh, equal to the fully dispatched average cost of plant A. In a more realistic case we would have uncertainty that would produce an expected price for energy and this would govern day-ahead choices. For the present examples we use a reasonable range of prices to examine the sensitivity to energy prices assuming a known energy price that keeps the calculations transparent.

Using energy prices in this reasonable range, $66 to $72.5/MWh, there can be an equilibrium that is sustainable in the presence of virtual offers. We illustrate the analysis for cases of $66 and $72 for the energy price.

With the least-cost solution and no virtual offers, the difference between commitment cost and energy revenues would appear in the day-ahead market. The lower energy price produces a day-ahead RSG of $260=40*(72.5-66). The higher price would produce an RSG of $20=40*(72.5-72).

As explained in the prior submission, if there are virtual offers, the perfect information equilibrium condition would require that the virtual bids and offers be at the same corresponding energy price. Initially assume that there are unlimited virtual supply offers at the assumed energy price. If the RAC produced the same optimal unit commitment, then the total cost would be the same. However the effect of the virtual offers would be to move the choice of plant A from the day-ahead to the RAC commitment. In the case of the $66 virtual offer, there would be 40 MW of cleared virtual offers in the day-ahead. Plant A would substitute in the RAC. There would be no day-ahead RSG, but the $260 RSG would now appear in the real-time market. In the case of the $72 offer, there would be 40 MW of virtual offers cleared in the day-ahead, and the RSG in real time would be $20.

The RAC protocol in the MISO does not necessarily produce the same total cost commitment. The rule is to choose the additional unit commitments to meet the forecast load and minimize the total commitment cost, but ignore the effects on the energy cost. Applying this rule to the example, consider first a case where plant C is not available. At the $66 price, virtual offers would be priced higher than the full dispatch cost of plant B at $61. Hence, the day-ahead market would commit plant B and not plant A. Virtual offers would clear for 15 MW. There would be no day-ahead RSG. In the subsequent RAC step, the only choice left is to commit plant A as well. In the real-time dispatch, the output for plants A and B would be 25 and 20 MW, respectively. The resulting total cost would $3295, or $65 more than the least-cost solution. There would be no RSG for plant B, but for Plant A the RSG would increase to $425, or $165 more than the RSG for the least-cost solution. The higher RSG results because the commitment of plant B changes the dispatch of plant A, reducing its output from 40 MW to 25 MW.

Using the higher price of $72, the same commitment, dispatch and total cost would result. However, the higher price would yield an RSG of $275, or $255 more than the least cost case.

A bad outcome for the RAC criterion appears when plant C enters the mix. The parameters for this plant have been constructed to be a near worse case for the RSG. Compared to plant A, plant C has almost the same fixed cost of commitment, only $1 less, but has a much higher energy cost just below the full dispatch cost of plant A. Hence, the full commitment and dispatch cost of plant C is much higher than for plant A, but plant C has a slightly lower commitment cost.

When plant C is included, it has no effect on the choice of the least cost solution. And if the RAC did not change the commitment there would be no effect of virtual offers other than to move the RSG from the day-ahead market to the real-time market.

Using the RAC rule that minimizes the commitment cost produces a different result. At the $66 price, again we find that plant B is committed and virtual offers clear for 15 MW. There is no day-ahead RSG. However, in the subsequent RAC, the choice is plant C rather than plant A, to save $1 in commitment cost. The total cost of the actual dispatch increases to $3659, or $429 more than the least cost solution. The RSG in real time would be $759, or $499 more than in the least cost solution.

At the higher price of $72, the same dispatch sequence would occur and the same total costs would result. However, now the RSG would be $699, or $679 greater than the corresponding RSG for the least cost solution with the higher price.

Dispatch Results (MW, Prices, and Costs; Load 45 MW)

Commit Units	A	B	C	D	Energy Price ($/MWh)	RSG ($)	Diff	Total Cost ($)	Diff
A	40	0	0	5	66	260		3230	
A&B	25	20	0	0	66	425	165	3295	65
B&C	0	20	15	10	66	759	499	3659	429
A	40	0	0	5	72	20		3230	
A&B	25	20	0	0	72	275	255	3295	65
B&C	0	20	15	10	72	699	679	3659	429

The accompanying table summarizes these six different cases with three different commitment decisions and two different energy price assumptions. Plant D has no fixed cost and is always available. Committing plant A alone is the least-cost solution and the solution that would appear if virtual offers have no impact on the total commitment. The two cases of committing plants A&B or B&C arise with virtual offers if the RAC follows the protocol to minimize commitment cost. Apparently the protocol for the RAC and the choice of energy pricing rule make a material difference in the impacts on total costs and on the RSG payments. However, there is no apparent connection between the total unit commitment and dispatch costs and the RSG payments.

Confounding Joint Effects and Marginal Impacts

The worst case in the examples involves the interaction of virtual offers, the RAC protocol and the inclusion of plant C. This case was constructed to produce about as bad an outcome as could be sustained in equilibrium between day-ahead and real-time markets. It is an empirical question as to how realistic this case is, but if costs and RSG allocations could be affected as much as this, a natural interpretation would be to consider altering the RAC protocol rather than attributing a large cost causation to the presence of virtual offers. In other words, the cost impacts arise from all three factors of energy price, RAC criterion and virtual offers. The examples by themselves do not isolate cost causation.

This interpretation is reinforced when we recognize that the RSG and total cost impacts shown are for the average virtual offer effects, not the marginal effects that underpin the cost causation principle and economic efficiency. One of the problems with the RAC protocol is that it is similar to the unit commitment problem in creating discrete effects that make the average impacts quite different than the marginal effect. The problem is not well-behaved in the same sense as the unit commitment with the ambiguity about the choice of the energy price. Every virtual offer does not make the same contribution to the total costs.

For example, consider the last case with all four plants eligible in the day-ahead market. Now relax the assumption of unlimited virtual offers and suppose there is a limited number of virtual supply offers and demand bids at the energy price. With many market participants there could be multiple virtual demand bids and supply offers at the clearing price. If the net of virtual bids and offers is no more than 14 MW, then plants B and D, coupled with the virtual offers, would not be sufficient to meet the 45 MW of required load in the day-ahead market. In this case, the commitment in the day-ahead market would need to choose between plants A and C. The least cost choice would be plant A and then the commitment would then not include plant B or C. Hence, for the cleared net of 14 MW of virtual offers, the day-ahead result would be the least-cost solution and the virtual offers would have no impact on total cost or the separate RSG payment. The sum of the individual cleared virtual offers and bids, and the resulting virtual schedule deviations, could be arbitrarily large and yet have no effect on total cost or RSG payments. The 15th MW of net virtual supply offers would have a discrete impact that accounted for all the effects on total costs and RSG payments. All net virtual offers above 15 MW would have no incremental effect on total costs and RSG payments. In other words, the marginal effects are zero except for the discrete impact of the critical net of virtual bids and offers. In applying cost causation principles, this presents the condition that the marginal effects are not the same as the average effects, and something other than cost causation is required to allocated the RSG payments.

These examples also illustrate why it is not deviations between day-ahead and real-time schedules that determine total costs or RSG payments. Even with no virtual offers and no deviations, the unit commitment and real-time pricing rules can produce material RSG payments. Further, the magnitude of the virtual offers clearing in the day-ahead market is not the key to triggering increased costs or RSG payments. Rather it is the appearance of the critical net of virtual offers operating in conjunction with the RAC protocol that could cause an expensive unit commitment choice. There can be a cost connection between the RAC and virtual offers, but it is not a function of deviations and does not follow the incentive arguments of economic efficiency and marginal cost causation outlined above.

This simple illustration reinforces the MISO conclusion that even in an idealized case it is not easy to isolate the reason for committing a plant. The total volume and the total deviation of cleared virtual offers do not determine the result. When coupled with the many other reasons for making RAC commitments, the nature of the RAC protocol and the ambiguity in determining real-time prices, the impact of virtual offers is proportionally less and almost always zero for marginal decisions.

As discussed in my prior submission, an alternative criterion for allocating the RSG payments would be to allocate the total RSG payment across those activities that have the lowest elasticity and therefore are least likely to respond and change the commitment or dispatch. This argues for allocating the RSG payments to real-time load. If the problem is that these RSG payments are too large, the analysis points to a combination of policies to change the energy pricing procedure and the RAC protocol to provide a better approximation of least cost unit commitment and economic dispatch.

Summary

Depending on the energy pricing procedure, RAC protocol and level of virtual offers, there can be impacts on total costs and RSG payments. In a similar way, total load and unit commitment rules affect total energy costs and RSG payments. But the cost causation analysis of total load that gives rise to energy LMP prices is not simply some unspecified connection between the elements. The cost causation principle applied to energy prices is the marginal change in total costs. The RSG arises because this energy price may not be sufficient to support the total costs incurred. A similar result applies to virtual offers. There may be an effect of virtual offers, but for the examples shown most cleared virtual offers have no marginal impact on total costs or RSG payments. The difference between the marginal cost causation analysis and the total cost impact of virtual offers is similar to the difference found between energy prices and total commitment and dispatch cost. This difference creates the need for RSG payments. The connection is complicated and cost causation principles applied to virtual offers do not provide much guidance for the allocation of RSG payments. The alternative principle of allocating residual total costs to relatively inelastic total load provides a mechanism that would not violate the principles of cost causation and would minimize further impacts on economic efficiency.

Appendix A

REVENUE SUFFICIENCY GUARANTEES AND COST ALLOCATION

William W. Hogan

May 25, 2006

(includes correction of minor typographical errors in original)

Introduction

These comments address the Revenue Sufficiency Guarantee (RSG) and associated cost allocation issues discussed in the April 26, 2006, Order of the Federal Energy Regulatory Commission (FERC) in the matter relating to the tariff of the Midwest Independent System Operator (MISO).[1] The focus is on the impact of virtual supply offers in the day-ahead market.

The purpose here is to explain the important role that virtual supply offers play in efficient markets and highlight certain characteristics of different market design features that lead to the use of virtual bidding and which affect total costs and the impacts of various cost allocation approaches. As discussed below, further empirical analysis would place material estimates on the impacts and allow for a better determination of cost causation for allocation of charges associated with unit commitment.

Attractions of Virtual Bidding

Electricity markets often include a day-ahead market with demand bids and supply offers to allow for day-ahead market-clearing schedules. There are many reasons for including an organized day-ahead market operated by the independent system operator. The day-ahead market provides additional information and allows for advance scheduling decisions to ensure reliability and planning for meeting the requirements of real-time load.

With an open real-time spot market, the day-ahead energy schedules become the equivalent of financial contracts that hedge energy price and transmission price uncertainties. This day-ahead hedging function is of value in itself, particularly because it allows for a daily reconfiguration of longer-term contracts and financial transmission rights (FTRs).

The day-ahead market necessarily includes certain features such as settlement of FTRs at the day-ahead price. The generation scheduling, price hedging and FTR settlement features call for a market design with the flexibility to support price convergence between the day-ahead market and the expected real-time price.

[1] Federal Energy Regulatory Commission, “Order Requiring Refunds, and Conditionally Accepting in part, and Rejecting in part Tariff Sheets,” Midwest Independent Transmission System Operator, Inc., Docket No. ER04-691-065, Washington D.C., April 25, 2006.

Restrictions on demand bids or supply offers in the day-ahead market could complicate price convergence with adverse effects on market efficiency.

Given the financial nature of energy schedules in the day-ahead market, it is natural to recognize that there need be no physical prerequisites for demand bids or supply offers in that market. The term "virtual bidding" has arisen to classify the strictly financial transactions where the expectation is that a day-ahead contract would not require actual delivery but would be netted out in the real-time market at the real-time price. The virtual energy schedule provides a fixed price contract one-day ahead where the risk associated with the uncertain real-time energy price is transferred between the parties.

Virtual bidding provides a number of significant benefits. Importantly, virtual bidding improves the flexibility that supports price convergence between the day-ahead and real-time energy markets. Price convergence improves the efficiency of the day-ahead commitment and energy schedules, reduces the cost of hedging, allows for efficient settlement of FTRs, and makes it advantageous for parties to utilize the liquidity provided in the market. Without the need to assure linked physical supply, it is easy for the virtual bidder to enter and seek to profit from any difference in the day-ahead price and the expected real-time price. With little or no constraints on entry, virtual bidders should provide highly competitive pressure to arbitrage between the markets and achieve price convergence. Although market participants with physical load or generation could also provide some of this arbitrage function, allowing for virtual bidding should greatly increase the competitiveness of the day-ahead market.

In real systems like the MISO, day-ahead markets with few or no constraints on virtual bids provide a valuable element of the market design. The system operator accepts the demand bids and supply offers, making no distinction between physical or virtual, clears the market and determines day-ahead market clearing prices and schedules.

While this framework works well for the day-ahead energy hedges, reliability requirements do make a distinction between the physical and virtual offers. In particular, with long-lead times to bring some physical units on line, the system operator prepares a separate evaluation of reliability in a Reliability Assessment Commitment (RAC) that removes the virtual supply offers and compares the likely physical generation capacity against the system operator's forecast of load (rather than bid-in load). If there is a deficiency, the operator commits additional physical units in order to ensure adequate capacity to meet the forecast load.

The unit commitment in the day-ahead market and RAC procedure includes three-part (physical) supply offers that recognize startup costs, minimum load costs, and energy bids up to the plant capacity. Virtual supply offers are in the form of energy bids only. The three-part bids and economic bid-in commitment and dispatch present the possibility that market clearing energy prices, in real-time or day-ahead, might not be sufficient to cover the full production cost of some generators that are near the margin of cost effectiveness.

The revenue deficiency arises from the all or nothing character of the individual unit commitment. Without the unit, the market-clearing price would support its commitment. But with the unit the dispatch would change and the market-clearing energy price would fall such that the unit would not receive enough energy revenues to cover its total bid-in production costs. In practice, this should arise with only a few generator units with high startup cost, low energy bids, and large enough capacities to materially change the dispatch.

The solution adopted to address the revenue deficiency is to provide a Resource Sufficiency Guarantee (RSG) for such generators. The RSG makes up the revenue deficiency for the committed plant. The RSG cost contributes to uplift charges that must be collected in some form. One goal is to keep these uplift costs (including the RSG cost) low and to allocate the costs in a manner that is practical and does not produce significant distortions relative to the efficient commitment and dispatch.

In addition to the inherent nature of unit commitment with all or nothing plant startups, RSG costs could arise from other sources. Conservative reliability criteria, self commitment decisions, and simple forecasting errors could lead to higher total unit commitments. The increased plant commitments could both raise the total startup costs and lower the market-clearing energy price, thereby increasing the RSG costs that appear in the market settlement.

The RSG costs can appear in the day-ahead settlement, real-time settlement, or both. The nature and magnitude of the RSG costs depend on many details of market design and participant or ISO behavior. However, with a well designed system it would be expected that RSG costs would be relatively small and attributable to the combined effects of many factors.

In the case of the MISO for the period under consideration by the FERC Order, my understanding is that total real-time RSG costs under discussion amount to as much as \$500 million.[2] This is a large number and raises the question of what could be causing the large revenue deficiency for plants committed by the system operator in the day-ahead market or RAC process. While the details matter, based on my general knowledge of these markets it seems unlikely that this large real-time RSG cost could be the result of any substantial impact of virtual supply offers and interaction with the RAC. The large RSG costs suggest that there may be too many units on-line, which would raise the total startup and no load costs and tend to depress the energy price, both effects adding to the RSG cost included in settlements. An important task would be to unpack the RSG costs in an attempt to quantify the effects of the various market design features or participant behaviors. This empirical analysis would allow a better parsing of cost causation and might identify changes in operating rules, cost allocations or participant behavior that would reduce both total costs and RSG costs. The evidence at least suggests that the RSG costs are high and the associated market-clearing energy prices are low.

Many empirical and detailed market design questions arise. However, in anticipation of such an empirical analysis, which would be done in order to support a cost causation argument for RSG costs, a discussion built around some simple market models

---

[2] See Midwest Independent System Operator spreadsheet, "RT RSG Market Wide Determinants.xls," at http://www.midwestmarket.org/publish/Document/469a41_10a26fa6c1e_-70340a48324a?rev=1 .

provides insight about what magnitudes would be important and what questions are likely to be important.

Market Models

The focus here is on the commitment stage and the virtual bidding issue. The analysis abstracts from other contributions to uplift payments, such as for operating reserves and ancillary services, to address the Resource Sufficiency Guarantee (RSG) and its allocation.

The preferred framework seeks consistent equilibrium descriptions rather than examples where bids, offers and prices are not consistent. Illustrative calculation of RSGimpacts, such as that provided by Ameren in this matter and discussed in the FERC Order,[3] often violate this condition and show perverse outcomes that include exploitable opportunities by violating some no-arbitrage condition. In other words, the bidding is not consistent with the solution, so the example only suggests that different bids would be expected, and say little about likely cost outcomes.

In addition, an appropriate framework would focus on day-ahead decisions and events. Cost causality should address the conditions in the time frame of the day-ahead market. This would include commitment decisions made as part of the day-ahead market or immediately afterwards under the Reliability Assessment Commitment (RAC). Commitments made in response to subsequent events may add to a real-time RSG cost but are not relevant for analyzing the effect of the virtual bidding.

The basic structure of the simplified market model used here includes three phases.

1. Economic day-ahead unit commitment with bid-in load and supply, including virtual demand and virtual supply.
2. A RAC commitment with forecast load and physical supply offers without virtual supply offers.
3. A real-time dispatch and market-clearing pricing.

The RSG cost addressed here is that arising because of three-part bids (startup costs, minimum load costs, and energy costs). There is some rule applied to determine day-ahead contracts and prices. This price determination may occur after phase one involving only the units committed based on the bids. Or price determination may apply after phase two and include units committed in the RAC step. Assume that the pricing rule includes virtual supply offers. For some units included in the day-ahead pricing, it may be that there is a deficiency between the day-ahead energy revenues at the market-clearing energy price and the associated three-part bid-in costs for startup, minimum load, and energy scheduled. The difference between bid-in costs and revenues accrues to a day-ahead RSG cost that must be collected from some market participants.

---

[3] FERC Order, para. 41, p. 15.

In real-time, there may be other units that have been committed in the RAC step but were not included in the day-ahead pricing. For some of these units, there may be a deficiency between the real-time energy revenues at the market-clearing energy price and the associated bid-in costs for startup, minimum load, and energy dispatched. Again, the difference between bid-in costs and revenues accrues to a real-time RSG that must be collected from some market participants.

The RSG costs may be collected as an uplift charge, along with other contributions to uplift for ancillary services and other cost recovery. The focus on RSG cost here follows the details of the MISO RSG cost calculation comparing energy production costs and energy revenues.[4]

Because of the three part bidding and discrete changes in total costs with changes in unit commitment decisions, analysis of the effects of virtual supply offers confronts certain complications. The approach here is to begin with a simplified model to highlight the impact of virtual bids, and then to consider the direction and likely magnitude of the effects in more realistic settings.

Begin with a simplified analysis that:

- ignores network effects,
- assumes a single dispatch interval,
- assumes no uncertainty, and hence no risk aversion,
- assumes perfect information,
- assumes no limits on the quantity of virtual bids,
- assumes costless virtual bids,
- assumes bidders act as price takers,
- assumes no exercise of market power, and
- applies a simplified model of commitment, dispatch and pricing.

The outcomes will be different under different rules for the market design. Consider two types of RAC commitment rules: a total RAC commitment covers all commitment decisions, and a partial RAC commitment that deals with incremental commitments relative to the day-ahead market schedule.

Total RAC Commitment

A common approach for RAC design is to ignore energy bids and optimize only over startup and minimum load costs for incremental commitments. However, to clarify the issues, consider first a RAC rule that (counterfactually) minimizes the total cost of startup, minimum load and energy, rather than ignoring the energy bids, and considering total commitment rather than just incremental commitment.

---

4 See the appendix for a summary of the RSG calculations.

Since there is perfect information, assume the forecast load is the same as the real-time load. By assumption of the total RAC commitment, virtual supply offers do not affect the commitment. Hence, there would be a consistent equilibrium.

With no uncertainty and perfect information, the commitment of units in the RAC step would the same as the units that are actually available in real-time.

Initially, assume that the day-ahead pricing is established at the end of phase one and does not include any additional units committed in the RAC. The day-ahead pricing is determined with the bid-in load and generation.

To simplify, assume that total day-ahead and real-time RSG cost is allocated to a third party not in the market. This allows a focus on the real-time market-clearing price (*p1*). The pricing rule may give rise to a real-time RSG cost.

Since there is no uncertainty and perfect information, the equilibrium virtual demand bids and virtual supply offers in the day-ahead market would be at the real-time price *p1*. Hence, the day-ahead market-clearing price must also be *p1*.

The RSG cost is the deficiency between market-clearing revenues and the bid-in costs. Therefore, the RSG cost for any unit would be the same as the difference between the virtual supply costs and the bid-in costs for the unit at the level actually dispatched in the pricing and settlement calculations.

If there is no quantity limit on virtual supply offers and the virtual supply cost for an equivalent output is less than the total bid-in costs for a plant, then the corresponding plant would not be selected in the phase one commitment. For the simplified model with no uncertainty, this implies that there can be no RSG cost in the day-ahead pricing result. Any real-time RSG cost would result from a subsequent RAC commitment of units that cost more than the virtual supply offers cleared in phase one, but that cost less than any alternative physical offers.

The real-time RSG arises from the additional units committed in the RAC. However, by assumption of optimal commitment in the RAC, these are the same plants that would have been committed and dispatched absent the virtual supply offers in the day-ahead market.

If there were no virtual supply offers, then all the commitment would be in the phase one commitment, there would be no need for additional commitment in the RAC, and the full RSG cost would appear in the day-ahead market defined by the same market-clearing price *p1*. There would be no subsequent real-time RSG cost.[5]

Apparently, with day-ahead pricing after phase one, the effect of the virtual supply offers in the day-ahead market would be to move the accounting for the RSG cost from the day-ahead pricing and settlement to the real-time pricing and settlement. But the virtual supply offers would not change the total cost or the total RSG cost.

---

[5] The assumption of a single dispatch period ignores possible contributions to the RSG costs from differences in the day-ahead dispatch interval, say an hour, and the dynamics in real-time that change the dispatch continuously.

If the day-ahead pricing and settlement occurred after phase two, using all the committed units, the day-ahead energy price should be the same as the real-time price and there would be no impact on total costs. The dispatch would be the same as the real time dispatch. Now any committed unit RSG costs appear in the day-ahead settlement. Hence, the day-ahead accounting and settlement would now include the full RSG costs. Again, the virtual supply offers would not change the total costs or total RSG costs.

All these arguments apply as well to to a commitment and dispatch in a network.

Suppose that the forecast load is not the same as actual load. The result would be to over or under commit in the RAC. Assuming that the real-time market still clears, there will be a market-clearing price that will differ from *p1*, but the same analysis applies relative to that market-clearing price. The unlimited virtual bids at the real-time market-clearing energy price assure that the day-ahead energy market clears at a price equal to the real-time price. Whether or not RSG costs appear in the real-time or day-ahead settlements will depend on the choice of day-ahead price determination after the phase one or phase two commitments.

Hence, there would be no total cost impact from the virtual demand bids and supply offers. The effect of the different RAC pricing rules would be to move the allocation of the RSG between day-ahead settlement and real-time settlement. But the existence of the virtual supply offers has no impact on the total cost or the total RSG.

When considering cost causation, there would be no cost resulting from the virtual supply offers in this assumed market structure in which there is perfect foresight and day-ahead prices are equal to real-time prices. An example in the appendix illustrates the equilibrium outcome for this hypothetical model.

If there is no place to allocate the RSG cost without distorting the electricity market, to minimize distortions a next best choice would be to allocate the RSG cost to the least elastic demand bids and supply offers. Under the assumptions, virtual demand bids and supply offers are infinitely elastic. Hence, the least distortionary allocation would have no RSG cost allocated to virtual supply offers or virtual demand bids.

The incentive-based and cost-causation arguments produce the same result. Under the total RAC commitment rule, there would be no RSG cost allocated to virtual supply offers.

Partial RAC Commitment

In this case, change the RAC rule to something closer to the actual MISO rule.[6] The day-ahead RAC in phase two minimizes startup and minimum load costs for commitments above the commitments made in the first phase. The commitments in the first phase are fixed for the second phase, and energy costs are not considered in the incremental RAC commitment. Thus the RAC step in phase two decides only part of the commitment

[6] See the appendix for sources.

Even with forecast load equal to actual load, this could result in a commitment that produced a total cost greater than would have occurred absent the virtual bids. The real-time market-clearing price could be different, say *p2*. As illustrated by example in an appendix, the partial RAC commitment could interact with virtual supply offers to produce a variety of outcomes through the impact on unit commitment and the associated startup and minimum load costs.

Under the partial RAC rule, there could be units not committed in phase one that would be committed in the RAC step, with lower startup and minimum load cost but higher total cost. This is inherent in the rule minimizing commitment costs rather than total costs.

However, with virtual supply offers and the partial RAC commitment there could be a different dispatch after the phase two RAC calculation. This could result in units committed in phase one that would not appear in the efficient total RAC commitment based on a dispatch without the virtual supply offers.

Since the virtual bids could affect the final commitment, the impact of the startup and minimum load bid components could create discontinuities between the virtual bids and commitments. This raises a question about the existence and nature of an equilibrium condition where the virtual bids, commitment, and real-time price are consistent. The examples in the appendix illustrate that there may be no simple equilibrium under these assumptions.

If there is a consistent equilibrium, the analysis of the balance between day-ahead and real-time RSG cost settlement is similar to the previous discussion. For the case with day-ahead settlement and prices determined after phase one, the analysis of the day-ahead market would be the same as before, with the virtual bids all made at the day-ahead market-clearing price of *p2*. There would be no RSG in the day-ahead market. All the RSG would appear in the real-time market.

Under the assumed market structure, the total cost of meeting load could be higher in this case than if there were no virtual supply offers. However, with no forecast error and hence no excess capacity commitment, the committed startup and minimum load costs would be lower and the market-clearing energy prices should be higher. The net effect should be to decrease the total RSG costs in the real-time market settlements, and therefore reduce the total RSG.

If there were no virtual supply offers in the day-ahead market, the phase one commitment would be the same as the efficient total commitment as in the total RAC commitment above. With forecast load equal to actual load, there would be no incremental commitment in the RAC step, and the corresponding and higher RSG cost would appear in the day-ahead market settlement.

Hence, with the partial commitment rule the virtual supply offers again move the accounting location for the RSG payment to the real-time as before. In addition the presence of the virtual supply offers could decrease the total amount of the RSG costs and increase the total cost of meeting load. The magnitude of the impact on total cost is difficult to calculate, but in the simple case the impact would be limited by difference between the startup costs of the inefficiently committed plants and the total costs of the efficient plants not committed. As the examples in the appendix show, this increase in total cost is not necessarily zero. But in practice in real systems, the increase should be both small and small relative to the total RSG costs. This is part of the intentional design feature of the partial RAC commitment rule.

If forecast load differs from real-time load, then there could be a different commitment in the RAC commitment step. With day-ahead pricing after the first phase but with no limit on virtual bids, all the RSG cost would still appear in the real-time market. With day-ahead pricing after phase two, the RSG cost would be moved to the day-ahead settlement. Without the virtual supply offers, there could be a mixture with some of the RSG cost appearing in the day-ahead and some appearing in the real-time settlement.

Again, if there is no place to allocate the RSG without distorting the market, a next best choice to minimize distortions would be to allocate costs to the least elastic demand bids and supply offers. Under the assumptions of this case, virtual demand bids and supply offers are infinitely elastic. Hence no RSG cost would be allocated to virtual supply offers or virtual demand bids.

If we follow a cost-causation rule based on total costs and allocate some costs to the virtual supply offers, the result would be to eliminate virtual supply offers in equilibrium. Since virtual supply offers are infinitely elastic, any charge assigned to virtual supply would reduce the offers to zero. If forecast load equals real-time load, this would eliminate any difference between the phase one and phase two unit commitments.

The implication is that the total cost impact of the virtual supply offer depends on the use of a partial RAC rule other than the total RAC commitment described above. This raises an interest in the reasons for using the partial RAC commitment rule in phase two and how to analyze the cost causation implications for virtual supply offers.

Uncertainty and Error

Introducing uncertainty into the model affects some of the details. However, if we assume that there are some participants who are risk neutral and do not have any quantity limits on virtual bids, the main conclusions above remain.

The perfect information assumption implies that everyone shares the correct probability distribution for the possible demand and supply conditions in real-time.

The risk neutral participants will ensure that the day-ahead market includes infinitely elastic virtual demand bids and supply offers at the expected real-time price.

As above, with day-ahead price determination done after the phase one commitment, there can be no RSG cost in the day-ahead settlement. All the RSG cost would appear in the real-time settlement.

With day-ahead price-determination done after phase two, RSG costs could appear in the day-ahead settlement. However, these RSG costs would be those that were determined at the expected real-time price. If as is likely, the real-time RSG cost is a non-linear function of real-time prices, the expected real-time RSG costs need not be equal to the real-time RSG costs at the expected real-time price. Hence, the result could be some RSG costs appearing in the day-ahead market settlement and some RSG costs appearing in the real-time settlement.

Furthermore, even with the efficient total RAC commitment, for a given set of bids payment of RSG cost in the day-ahead settlement could result in an increase in total RSG costs because in effect the suppliers would receive the greater of the day-ahead RSG payment or the real-time RSG payment. If the bids are discretionary, however, then this impact would be mitigated if not eliminated by competition for the RSG payment as generators reduced their bids to ensure being committed and able to receive the expected RSG cost payment.

As before, with the efficient total RAC commitment, the virtual supply offers have no impact on the total cost or total RSG cost. With partial RAC commitment rule, the presence of virtual supply offers can increase the total expected cost and reduce the RSG cost.

Risk Aversion and Credit Limits

Uncertainty and risk aversion create the incentive to hedge, and virtual bids provide an important hedging tool. This hedging motivation complements the arbitrage function of virtual bidding.

With a finite number of market participants who are credit constrained or risk averse, or both, the simplification of infinitely elastic virtual demand bid and supply offers no longer applies. Even with perfect information in the sense of the same probability distribution for real-time conditions, virtual demand bids will aggregate into a downward sloping virtual demand curve and virtual supply offers would aggregate into an upward sloping virtual supply curve.

Market participants with physical load exposed to the real-time price might be prepared to pay a premium for load hedging and could bid above the real-time expected price in the day-ahead market. But financial participants seeking to arbitrage between the markets would require a premium to bear the resulting risk and would offer virtual demand bids below the real-time expected price. The aggregation would be a downward sloping demand curve. A similar argument would apply to supply offers made by those who were hedging in the day-ahead or arbitraging the difference in prices, resulting in an upward sloping aggregate supply curve.

The equilibrium result could be a day-ahead price above or below the real-time expected price, depending on the varying degrees of risk aversion of the market participants. However, the virtual demand and supply curves should be more elastic than the physical demand and supply curves. With the presence of a significant number of arbitrage participants, the difference between day-ahead and real-time expected energy prices should be small.

Now there could be RSG costs in the both day-ahead and real-time settlements under all the pricing and RAC rules discussed above. The directional impact of virtual supply offers should be the same as in the previous discussion, and to the extent that the strictly financial supply and demand offers are highly elastic, the magnitudes should be similar.

Maintaining the competitive market and perfect information assumptions, in the case of the total RAC commitment the total cost would not be affected by the virtual supply offers. This follows by the optimality assumption implying that the commitment is the same with and without virtual supply offers. As before, in the case of the partial RAC commitment, the virtual supply offers could increase total cost by inducing incremental commitments in the RAC phase without optimizing total costs.

Conflicting Objectives

Under the assumed model structure, the partial RAC rule therefore gives rise to the possibility of increased costs to the extent that bid-in load and supply differ in the day-ahead from the expected conditions in real-time. If the day-ahead offers are consistent with real-time and there are no virtual supply offers, the partial RAC would result in the efficient solution. This perfect consistency would be an unusual condition.

In the presence of uncertainty, some less risk-averse bidders may choose to remain exposed to real-time prices rather than pay a premium for a day-ahead hedge. In the real system, there may be other options to secure supplies between the day-ahead and real-time, such as through imports that become available on a different schedule. Or it may be better simply to accept some of the exposure to real-time prices. Hence, it may be optimal even for a competitive market participant to less than perfectly hedge its real-time position.

This produces a fundamental asymmetry for the system operator. In effect, there is a market externality where the market participants act as though there will be a reliable dispatch in real-time and they discount the systemic effect of inadequate total generation availability. The system operator has the responsibility to ensure that there is enough capacity and enough operating reserves committed in advance to meet even a high estimate of the total load. This may require the system operator to take a conservative position that will on average result in too much commitment sufficient to meet a forecast load higher than the bid-in load. The approach is similar in spirit to contingency based dispatch rather than expected value dispatch in the presence of uncertain events. The cost of any conservative commitment would be the excess of startup and minimum load costs for the extra units.

This conflicting objective between the efficient bid-in load commitment as seen from the perspective of the load and the forecast load commitment seen from the perspective of the system operator to account for the externality presents a tradeoff. One way to address the tradeoff is to adopt the partial RAC commitment rule that minimizes the startup and minimum load costs of the incremental commitment. This adds some cost compared to the case of bid-in load unit commitment, but it avoids some cost for the case of conservative unit commitment. In the real system, the partial RAC could represent the optimal balance.

Hence, the partial RAC rule can be seen at least as a reasonable compromise that addresses conflicting objectives. The rule deviates from the bid-in load solution with or without the presence of virtual supply offers. Furthermore, the analysis of increased costs that could arise from virtual supply offers depends on the assumption that without the virtual supply offers the partial RAC would be in effect replaced by the total RAC commitment. But given the requirement to address the reliability need, this may not be the right approach. Given the externality argument, the probably small cost impact of the virtual supply offers would be further mitigated.

Self Commitment

The MISO market monitor in his comments to the Commission raised a potential concern that load serving entities might be able to use virtual supply bids in the day-ahead market strategically to lower their costs.[7] If some of the market participants have partially unhedged loads and own significant generation, the different RAC commitment rules could have an impact on prices and cost allocations.

A principal concern may be with the hypothetical case of a load serving entity that controlled some generation but was still a net buyer. This possible case applies to an LSE that also owns generation but seeks lower energy prices. With an excess unit commitment, the market-clearing energy price could be reduced. Suppose the market rules would permit the LSE to underbid load in the day-ahead market and withhold offers for an equal amount of generation and that the ISO could not detect and deal with this behavior. If the system operator must follow RAC rules to recognize only the bid-in generation, the system operator would see this condition as having a forecast load greater than the bid-in load, and insufficient offered generation.

Under the assumption that the behavior cannot be detected and precluded, it is possible that, either because of the tariff rules or because the system operator did not know about the likely availability of the withheld units, the system operator would commit additional units in the RAC step and raise total costs. In real-time, the LSE would self-commit the efficient units. The result would tend to be a lower market-clearing energy price in real-time and in the day-ahead market as well. The LSE would benefit from the lower market-clearing price. The increased costs would appear in RSG payments. This hypothetical case could potentially result in a higher total cost and a consistent lower energy price, both in the day-ahead and real-time settlements.

The above concern, if found to be real, would motivate two policies. First it would reinforce the use of the partial RAC rule rather than the total RAC rule outlined above. The partial RAC rule would mitigate the cost of the excess commitment and would likely lessen the impact on the real-time energy price because the excess units would by construction have higher energy bids for the dispatch.

Second, it might motivate a policy of assigning some or all of the incremental total costs, in the form of RSG allocations, to the LSE that underbid its load, if the partial RAC rule did not resolve the problem and the market monitor concluded that the RTO

---

[7] Potomac Economics, Ltd., "Motion to Intervene and Comments of Potomac Economics, Inc," FERC Docket No. ER04-691-065, November 17, 2005.

did not have the information to prevent the problem. The RSG allocation could be based on the difference between the real-time load and the day-ahead load.

Any allocation of RSG costs based on the difference between real-time and day-ahead load would confront the problem that underbidding day-ahead load is equivalent to bidding the full load and making a companion virtual supply offer. Rather than underbidding the load, the LSE would be able to achieve the same end by bidding the full load but offering virtual supply for the equivalent amount of withheld generation in the day-ahead market. Neither the virtual supply nor the withheld generation would be available in the RAC step and there would be excess commitment of capacity. But now day-ahead bid-in load would be the same as real-time load of the LSE. Hence, in order to allocate RSG costs to the LSE it would be necessary to allocate costs for the difference between bid-in load and real-time load plus the virtual supply offer by the LSE.

In the hypothetical case discussed above, the issue of strategic underbidding would apply only to certain LSEs that could profitably withhold generation in the RAC commitment. By contrast, LSEs without such a capability, including all the financial arbitragers who use virtual bidding, would not have these incentives or an ability to withhold generation in this way and thus should not be allocated these costs.

The market monitor should continue to follow this issue. However, use of the partial RAC rule mitigates these potential effects. In any event, this concern is not relevant to virtual bidders who do not serve load in the MISO market.

RSG Cost Allocation Effects and Tradeoffs

The RSG cost is one source of uplift allocations that must be recovered. Cost causation arguments provide guidance as to the allocation, but the focus of cost causation should be on the total costs and benefits, not just the partial analysis of the direct effect on a particular settlement component. Absent a marginal cost analysis, cost causation as a criterion confronts the added problem of dealing with joint or fixed costs where there is no unique allocation that results from the principle and any allocation contains certain arbitrary elements. These arbitrary allocation decisions, while unavoidable, raise the question of the incentive effects and the resulting distortions that follow. The general principle after marginal cost causation allocation would be to assign other costs in a way that is both practical and minimizes distortions relative to the efficient solution. This implies that the costs should be allocated to the least elastic components of the system.

For the simple models above, the analysis of the effect of virtual supply offers indicates that the total cost causation is likely to be small or zero, and in some cases the effect would be to reduce the RSG cost. Furthermore, in the partial RAC commitment case, the cost causation that could occur is really as much a product of the commitment rule more than the role of virtual supply offers. After accounting for the tradeoffs that motivate the partial RAC commitment rule in dealing with market externalities, there may be little or no impact on total costs as a result of the use of virtual supply offers.

A full empirical analysis would be required to validate this conclusion, and might lead to consideration of changes in market design and the commitment rule rather than allocation of RSG costs to virtual bidders. However, the discussion of the conflicting objectives and tradeoffs that motivate the partial RAC rule provides reasons for maintaining the rule at this time. If there are to be changes to mitigate cost effects or virtual supply impacts, one desiderata would be to find an alternative commitment rule that is independent of the virtual supply offers.

The principal exception to the judgment that virtual supply offers would have limited or no impact under the simplifying assumptions above, would be in the case of the hypothetical argument above applied to the case of LSEs. However, this analysis implicates the incentive problems that might arise for LSEs, but not for other market participants that provide virtual supply offers. In other words, the hypothetical of LSE's withholding generation at the RAC phase provides a basis for potentially allocating RSG costs to some load-serving entities that submit virtual supply offers, but not to virtual supply offers by entities that do not serve load.

Would an assignment of RSG costs to LSEs for underbid load and virtual supply offers imply that RSG costs require an assignment of RSG costs to all virtual supply offers? In the analysis above, there is no justification provided for such a policy. This policy might arise if there were some other effect or market design feature identified that would implicate virtual supply offers from other than LSEs, particularly from entities making purely financial transactions. Or the argument would have to be that it would be impractical to distinguish the virtual supply offers from LSEs and those from other market participants. This seems a difficult case to make given the existing apparatus for market monitoring.

Any allocation of RSG costs based on a cost causation analysis would confront the fact that only a portion of the RSG costs could be attributable to the effect of virtual supply offers, and even the direction of the impact is uncertain. The result would depend very much on the details of market design and configuration of generation, load and the grid. This would be a challenging task.

It is not challenging to consider the effects of an allocation of RSG costs to all virtual supply offers. The impact would be the greatest on the most elastic offers, and these would tend to be the offers of the financial bidders. The results would be to reduce or eliminate participation by exactly those virtual supply offers that are important in performing the arbitrage function between day-ahead and real-time prices and in expanding liquidity to reduce the costs of day-ahead hedges.

Allocation of RSG costs to virtual supply offers presents another problem if, as in the case of the MISO, there are different RSG cost allocation rules in the day-ahead and real-time market. As discussed above, even when virtual supply offers have little or no impact on the total costs or total RSG costs, the presence or absence of highly elastic virtual supply offers can have a material effect on whether the RSG costs appear in the real-time or day-ahead settlement. The unintended consequence of allocating real-time RSG costs to virtual supply offers could be to shift the RSG costs to the day-ahead market where there is a different allocation rule.

Allocation of RSG costs to virtual supply offers also creates a negative feedback in that the reduced volumes make any total cost allocation potentially volatile. The cost allocation rule tends to reduce the volumes over which the costs would be allocated. In principle, with little load deviations and little virtual supply, any error in calculating the incremental RSG cost could result in a very high and volatile per MW cost allocation. This would increase the risk of making virtual supply offers and further reduce liquidity in the day-ahead market. The problem would be compounded by a policy that did not isolate the incremental RSG cost and simply allocated all of RSG costs to the load deviations and virtual supply offers.

Virtual bidding provides real benefits through arbitrage and hedging functions. Assigning significant RSG costs to virtual supply offers would most impact the financial hedging and arbitrage that is not related to the possible LSE concern discussed above.

An alternative to preserve the benefits of virtual bidding would be to limit cost allocation to those LSEs that hypothetically could withhold, assuming the concern I have discussed above turns out to be real. Or don’t assign RSG costs to either underbid loads or virtual supply offers and allocate all RSG costs to real-time load. This approach would rely on the market monitor to deal with any LSE attempts to manipulate the partial RAC commitment.

Appendix I

Midwest ISO Revenue Sufficiency Guarantee Definitions[8]

Day-Ahead Market

Payments to generators

Units committed in the day-ahead market are guaranteed to recover their production costs. These costs as defined by the Midwest ISO include:

- Start up costs – costs incurred per start-up over the run time of the unit.
- No-load costs – are costs for operating a generation resource at zero MWs.
- Energy offer costs – price at which a resource has agreed to sell the next increment of energy

Units are entitled to cost recovery only if the hours for which there is a shortfall occur outside of a continuous period of operation, defined as a period of operation bound by a scheduled start-up and shut-down time. In addition, the unit can not have a "must-run" status, meaning that the unit was committed at the request of the market participant. A generator's "make whole payment" is calculated as:

$$Minimum[0, \sum_{Hours}((ProductionCosts) \times (-1)) - \sum_{Hours}((DayAheadLBMP) \times (ClearedAssetSchedule))]$$

Source: Midwest ISO "Overview – Day-Ahead & Real-Time Revenue Sufficiency Guarantee (RSG)"

The make whole payment is spread evenly across all eligible hours. The day's total make whole payment is compared to a mitigated make whole payment calculated by the ISO. If the actual payment exceeds the mitigated payment by $1000 and is 200% greater than the mitigated value, the make whole payment is reduced to the mitigated payment.

Collection of Payments from Load

Make whole payments are collected from asset owners with day-ahead withdrawal volume, including units with:

- Cleared day-ahead asset load
- Day-ahead cleared net virtual schedules acting as load
- Day-ahead physical, bilateral transaction MISO exports

Once a participant is scheduled to purchase energy in the day-ahead market, they are charged a DA revenue sufficiency charge, calculated as:

---

8 Summary prepared by Alexis Maharam of LECG.

$$\sum HourlyMakeWholePayments \times (-1) \times [(OwnerDAWithdrawals)/(MISOTotalDAWithdrawals)]$$

Source: Midwest ISO "Overview – Day-Ahead & Real-Time Revenue Sufficiency Guarantee (RSG)"

This charge is allocated and distributed to generators scheduled in the DA market with revenue shortfalls.

Real-Time Market

Payments to generators

Units committed to run by any of the Reliability Assessment and Commitment (RAC)1 processes are guaranteed their production costs as defined in the day-ahead market. Eligibility is defined in each commitment period, the collective, continuous hours during which an asset has been committed. In each eligible hour, an asset receives a make whole payment calculated as follows:

$$[\sum_{Hours}((\Pr oductionCosts) \times (-1)) - \sum_{Hours}((\mathrm{Re}\, alTimeLBMP) \times (ClearedAssetSchedule))]$$

Source: Midwest ISO "Overview – Day-Ahead & Real-Time Revenue Sufficiency Guarantee

Collection of Payments from Load

Make whole payments are funded by the following activities in the real-time market:

- Real-time load deviating from the day-ahead schedule
- Day-ahead resources not operating as anticipating in real-time
- Changes in the real-time physical bilateral transactions from the day-ahead market.

As in the day-ahead market, each owner is responsible for their hourly share of funding as follows:

$$\sum HourlyMakeWholePayments \times [(OwnerRTActivity)/\{Maximum(MISOCommitment),(AllRTActivity)\}]$$

Source: Midwest ISO "Overview – Day-Ahead & Real-Time Revenue Sufficiency Guarantee (RSG)"

Notes and Sources:

1. The Reliability Assessment and Commitment processes aims to optimize selection of resources by minimizing commitment losses while meeting 100% of load forecast. RAC considers start-up and no-load offer at a minimum load only. If necessary, the transmission provider may run a RAC process to ensure reliability, employing start-up and no-load offers last submitted by market participants. Resources selected by the RAC must adhere to the dispatch to the extent feasible in the real-time market. (MISO Tariff 536-538).

2. Sources:

(a) Midwest ISO Business Practice Manual for Market Settlements Version 8. Approved 12/22/2005.

http://www.midwestiso.org/publish/Document/20f443_ffd16ced4b_-7e670a3207d2?rev=10

(b) Midwest ISO “Overview – Day-Ahead & Real-Time Revenue Sufficiency Guarantee (RSG)”.

http://www.midwestmarket.org/publish/Document/10b1ff_101f945f78e_-737c0a48324a/_.pdf?action=download&_property=Attachment

(c) Open Access Transmission Tariff for the Midwest Independent Transmission System Operator, Inc. Effective March 1, 2005 (MISO Tariff).

Appendix II

Illustrative Unit Commitment and Dispatch Examples

The examples here illustrate that even under the simple case of perfect information and no forecast error there can be Revenue Sufficiency Guarantee (RSG) costs that arise without the presence of virtual supply offers. In the case of the total RAC commitment, the virtual supply offers do not affect total RSG costs, but do affect whether the RSG costs appear in the day-ahead or real-time settlement.

In the partial RAC commitment, the virtual supply offers can have an impact that could raise costs and preclude any simple market equilibrium. Just as there may be no energy price that is consistent with the unit commitment and dispatch, giving rise to RSG costs, there may be no pure strategy equilibrium between day-ahead and real-time under perfect information and infinitely elastic virtual bids.

The examples assume perfect information, no error in forecasting, no market manipulation, and energy prices set at marginal cost given the commitment.

There are three plants:

Plant	Startup Cost ($)	Minimum Load (MW)	Capacity (MW)	Energy Bid ($/MWh)	Average Cost at Capacity
A	700	0	40	55	72.50
B	50	0	9	60	65.56
C	0	0	20	66	66.00

Assume demand is 45 MW and plant C is always available.

Least Cost Solution

The efficient solution commits plant A but not plant B. Plant A is fully dispatched and plant C is dispatched at 5 MW. Total cost is $3230. The energy price is $66. There would be a $260 real-time Revenue Sufficiency Guarantee (RSG) cost for plant A, covering the difference between total production cost and the energy revenues (700+40*55-40*66). The RSG cost appears without the introduction of virtual supply offers.

The effect of virtual supply offers would depend on the RAC procedure and pricing rules.

Total RAC Commitment

If the commitment were always the commitment that would be made in the absence of virtual supply offers, then the efficient solution would apply in real-time with a market-clearing energy price of $66. This same price would also apply in the day-ahead virtual bids. In this case, the day-ahead solution and contracts would be for 9 MW with plant B, and 36 MW of virtual bids at $66. Since the energy revenue is greater than the production cost for plant B, there would be no day-ahead RSG. The bid from plant B becomes just like a virtual schedule, the plant is not actually committed, and the startup cost is avoided.

In real-time, the dispatch would be for 40 MW from plant A and 5 MW from plant C, with a market-clearing price of $66. There would be a $260 real-time RSG cost for plant A, (700+40*55-40*66), settled in real-time or day-ahead depending on the pricing rule as after phase I or phase II. The virtual schedules would net out with the real-time dispatch at the equilibrium price. This would be an equilibrium solution for energy prices in real-time and day-ahead.

Hence, the virtual supply offers do not affect total costs or total RSG costs, but they do affect the settlement timing of the RSG cost.

Partial RAC Commitment

If we include virtual bids at $66 in the day-ahead market, then plant A is more expensive than the virtual bid. But when fully dispatched plant B is less expensive than the virtual bid. Hence, the commitment and dispatch with virtual supply offers includes Plant B but not plant A, and the market clearing energy price is price is $66.

If we keep plant B in the commitment, but remove the virtual supply offers, then we must commit plant A in order to meet demand. The real-time result would be to fully dispatch A at 40 MW, and back off plant B to 5 MW. Total cost would be $3265. Now the real-time energy market-clearing price is $60, which would be inconsistent with the virtual bids.

By comparison, if we use $60 as the virtual bid in the day-ahead market, then we would not commit either plant A or B in the dispatch with virtual bids, and the day-ahead schedule would include only virtual awards. Then the real-time solution would be the efficient solution, but the energy price would be $66, which would be inconsistent with the virtual bids.

Apparently there is no market-clearing energy price in equilibrium across real-time and day-ahead that supports the resulting partial RAC commitment. And any solution that commits plant B would raise total costs.

The equilibrium existence problem arises by requiring that plant B committed in the dispatch with virtual bids is also included in the commitment after the virtual supply offers are removed.

Endnotes

---

i William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University and a Director of LECG, LLC. These comments were prepared at the request of DC Energy. The earlier comments were prepared at the request of Edison Mission Energy. This paper draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Australian Gas Light Company, Avista Energy, Barclays, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, Calpine Corporation, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, Conectiv, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Duquesne Light Company, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, GPU Inc. (and the Supporting Companies of PJM), Exelon, GPU PowerNet Pty Ltd., GWF Energy, Independent Energy Producers Assn, ISO New England, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, JP Morgan, Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario IMO, Pepco, Pinpoint Power, PJM Office of Interconnection, PPL Corporation, Public Service Electric & Gas Company, PSEG Companies, Reliant Energy, Rhode Island Public Utilities Commission, San Diego Gas & Electric Corporation, Sempra Energy, SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, TransÉnergie, Transpower of New Zealand, Westbrook Power, Western Power Trading Forum, Williams Energy Group, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).