

Going short under the SMD

Scott Greene, Mark Niehaus and Pankaj Sahay of PricewaterhouseCoopers look at the effect of settling a short position in the day-ahead market under the Federal Energy Regulatory Commission's proposed standard market design

The Federal Energy Regulatory Commission's (Ferc) standard market design (SMD) proposals have received much attention – so much so that the US interstate energy regulator has now extended the period of public consultation, allowing energy companies more time to understand the concepts behind the 600-page plan.

Here we build on last month's article – which examined at the potential impact of the proposals on load-serving entities (LSEs) – by looking at settling a short position in the day-ahead market under the SMD (see *EPRM* October 2002, page 20).

Base case

First we consider the base case. We assume the LSE has an uncertain load obligation of around 100 megawatts (MW) and that the peak load will be either 100MW or 120MW – with equal probability – for the hour of interest.

We assume also that there are two generator companies: company A, which has a base-load plant and a combined-cycle unit, and company B, which has a peaking plant. The LSE has a forward bilateral contract for 100MW of on-peak power from company A at \$20 a megawatt hour (MWh). Under normal conditions, company A meets this obligation using excess capacity from its base-load unit. Company A can also generate an additional 5MW at \$30/MWh and another 15MW at \$50/MWh.

When the peak load is 120MW, half the time the LSE can meet the remaining 20MW of demand with an hourly purchase from company A. We assume that company A prices the additional 20MW block to serve the LSE peak demand at the marginal rate of \$50/MWh. However, during congested conditions – the other half of the time the load is above 100MW – company A cannot arrange transmission service to the LSE, and the LSE has to buy 20MW from company B at \$250/MWh.

Table 1 shows the possible outcomes, underlining that the uncertainty in demand and congestion means uncertain revenue for each entity. The expected

revenue for company A in that hour is \$2,250 $((0.5 \times 2,000) + (0.25 \times 3,000) + (0.25 \times 2,000))$, with a minimum revenue of \$2,000 and a maximum revenue of \$3,000. Similarly, the expected revenue for company B is \$1,250, but with a variation between a maximum of \$0 and a minimum of \$5,000. Hence the LSE, on average, expects to pay \$3,500 to serve demand in that hour, with a maximum possible cost of \$7,000 and a minimum of \$2,000. The LSE has limited options for mitigating the risk of congestion and variability of demand.

Case study: LSE covers variable short position in DAM

Last issue we examined the impact of a two-settlement spot market of the SMD by comparing the pre-SMD market solution to the case corresponding to the LSE exposing the variable 20MW position in

the prices at each location are the same, neglecting losses. However, when there is congestion, the price at every location in the network can be unique. The LMP reflects the marginal cost of serving the next increment of load at a specific location. The LMP is different for each location because, in general, there is a unique minimum cost combination of power injections that can match the corresponding withdrawal of power at a location while exactly balancing the flows on the constrained transmission lines.

Now let us assume that the LSE seeks to settle the additional 20MW in the day-ahead market (DAM) to cover the possibility of high demand. The day-ahead market offers more certainty than the real-time, balancing market (BM), which is subject to unexpected events such as unplanned outages and unexpected weather.

In this case, since the DAM demand is

In the absence of congestion, the prices at each location are the same, neglecting losses. But when there is congestion, the price at every location in the network can be unique

the real-time balancing market (BM). One aspect of the SMD is that the dispatch of the generation pool and locational marginal prices (LMP) are determined by an optimisation programme that minimises the total pool cost to serve load while respecting the security constraints of the grid. Tables 2 and 3 (see page 54) display the dispatch and prices, respectively, for the possible scenarios. Note that in the absence of congestion,

120MW, there is the potential for congestion in both the DAM and the BM. It is important to consider the various outcomes of this strategy, assuming that the LSE holds or does not hold a congestion revenue right (CRR), which is settled in the DAM. CRRs are financial contracts for difference (see box, page 55).

There are six possible outcomes – set out in table 4 (on page 54) – which result from the uncertainty in the actual load and

Table 1: Pre-SMD market solutions

Load	100MW	120MW	120MW
Congested	No	No	Yes
Probability	50%	25%	25%
Company A revenue	\$2,000/hour	\$3,000/hour	\$2,000/hour
Company B revenue	0	0	\$5,000/hour
LSE revenue	-\$2,000/hour	-\$3,000/hour	-\$7,000/hour

Table 2: Least-cost constrained dispatch

LSE load	Company A base output	Company A \$30 block	Company A \$50 block	Company B \$250 block	Flow on constraint
100MW	100MW	0	0	0	50MW
120MW	100MW	5MW	15MW	0	60MW
120MW	100MW	5MW	11MW	4MW	55MW

Table 3: Locational marginal pricing

LSE load	Constraint rating	Probability	Company A LMP	Company B LMP
100MW	70MW	50%	\$30	\$30
120MW	70MW	25%	\$50	\$50
120MW	55MW	25%	\$50	\$130

the possibility of congestion occurring in either the DAM or the BM or both. Under the SMD, both the DAM and BM are financially binding. Differences between the DAM and BM quantities are settled at the BM prices. In this example, deviations between the DAM and BM dispatch are due to the difference between scheduled load and actual load or the occurrence of congestion.

The resulting revenues for each outcome are determined as follows:

- calculate the DAM charges for the quantities and prices shown in tables 2 and 3 corresponding to the DAM scheduled load and congestion condition;
- determine the quantities from table 2 corresponding to the BM load and congestion condition and compute the differences between the DAM and BM quantities; and
- settle the differences at the BM prices from table 3 corresponding to the BM conditions.

In the first instance – where there is no congestion in the DAM and the actual load is 100MW – the LSE pays \$2,000 for the contract with company A, then settles on 20MW in the DAM at \$50/MWh. In the BM, that charge is partially offset by a refund for being short 20MW, credited at the BM price of \$30/MWh. Company A receives \$2,000 from the LSE, plus \$1,000 for 20MW at \$50/MWh in the DAM. However, the lower actual load means company A refunds \$600 in the BM (20MW multiplied by the BM price of \$30/MWh).

In the instances when there is congestion in the DAM (cases 2, 4, and 6), the LSE/company A transaction is assigned a congestion charge of \$8,000, reflecting the difference in the marginal value of

power between source and sink. The \$8,000 charge is simply the scheduled quantity of the transaction multiplied by the difference in the LMP from sink to source (100MW * (\$130 – \$50)).

The congestion charge would be completely offset if the LSE owned a CRR from company A to the LSE. CRRs are only settled in the DAM. In the BM, deviations from the DAM quantities are settled at the BM prices, which reflect the actual real-time congestion.

In the second instance, in addition to the charges associated with the fixed 100MW schedule, the LSE is also charged another \$2,600/hour in the DAM for the 20MW peak at \$130/MWh, but still receives a refund of \$600/hour in the BM when only 100MW is actually drawn. Similarly, company A receives an additional \$800/hour (16MW * \$50/MWh) credited in the DAM, but then is charged \$480/hour in the BM, because the generation is not needed. Company B receives \$1,000 from the DAM and then refunds \$120 in the BM when the peaking unit is not dispatched.

In the third case, the scheduled demand in the DAM matches the actual demand in BM and there is no congestion in the BM

or the DAM. The DAM dispatch then matches the BM dispatch, and there are no deviations between scheduled quantities and actual quantities to be settled in the BM. In this case, the LSE pays \$2,000 for the 100MW scheduled bilateral and \$1,000 for the additional 20MW peak. Similarly, company A receives the \$2,000 for the scheduled bilateral and also receives \$1,000 for providing an additional 20MW at the DAM spot price of \$50/MWh.

Under the same conditions, if there was congestion in the DAM – case number 4 – then once again the company A/LSE transaction is assessed a \$8,000 congestion charge in the DAM and the LSE must pay the additional \$2,600 for the peak 20MW. Company A receives \$800 for dispatching 16MW above the bilateral schedule (see table 2), and company B receives \$1,000 for the 4MW dispatched. In the BM, company A receives another \$200 for dispatching another 4MW, while company B refunds \$200 for not dispatching the 4MW – but also does not incur the costs of producing that energy. Since the LSE day-ahead scheduled load matches the actual load, there is no deviation settled in the BM and no refund is received.

Even when there are no deviations between the actual demand and the bid demand, congestion can still cause deviation between the DAM and the BM dispatch. The difference could be due to other factors influencing the real-time system that were not accounted for in the DAM, such as the unexpected loss of reserves not involved in the dispatch or the unplanned loss of transmission facilities.

Finally, in the last two rows of table 4, we assume the DAM and BM schedules match, and that there is congestion in the BM and either congestion or no congestion in the DAM. In the absence of congestion in the DAM – case 5 – the LSE pays \$2,000 for the bilateral schedule and \$1,000 for the peak 20MW. In the BM, the congestion results in an increase to the LMP at the LSE

Table 4: Outcomes assuming LSE covers 20MW in the day-ahead market (DAM)

LSE DAM (MW)	LSE actual load (MW)	Congested BM	Congested DAM	Company A revenue (\$/hour)	Company B revenue (\$/hour)	LSE revenue (\$/hour)	A to LSE CRR (\$/hour)
120	100	No	No	2,400	0	-2,400	0
120	100	No	Yes	2,320	880	-12,000	8,000
120	120	No	No	3,000	0	-3,000	0
120	120	No	Yes	3,000	800	-12,600	8,000
120	120	Yes	No	2,800	1,000	-3,000	0
120	120	Yes	Yes	2,800	1,000	-12,600	8,000

of \$80 to \$130/MWh, but as there is no deviation from the DAM quantity, there is no additional charge to the LSE.

We should bear in mind here that if the LSE could implement demand reduction – such as curtailing non-critical loads – any deviation from the DAM schedule would be credited at the \$130/MW BM price. In other words, participants have incentives to deviate from DAM schedules when real-time conditions cause BM prices to diverge from DAM prices.

Company A again receives the \$2,000 from the LSE, plus 20MW multiplied by \$50/MWh in the DAM, then refunds 4MW at the \$50 price in the BM since real-time congestion forces the unit to be backed-down. Company B only gets the BM payment for the 4MW dispatched at \$250/MWh.

In the last case, as there is congestion in both DAM and BM, the LSE's excess 20MW is charged at the \$130/MWh LMP in the DAM, the company A/LSE transaction includes an \$8,000 congestion charge and again there are no BM deviations. Company A receives the \$800 for dispatching 16MW at \$50/MWh and company B gets the \$1,000 for dispatching 4MW at \$250/MWh. As there are no deviations between the DAM and BM, all revenues are determined by the DAM settlement.

The value of CRRs

The strategy of covering the 20MW peak in the DAM results in an expected cost to serve load of \$3,500 if the LSE holds a

Congestion revenue rights under Ferc's new rules

In the pre-SMD market, congestion is managed by restricting the availability of transmission – known as quantity rationing. The SMD market is characterised by price rationing.

When the transmission system is congested, the spot prices differ throughout the grid and participants buying power at one location to serve load at another can be exposed to big price differentials. Congestion revenue rights (CRR) – analogous to firm transmission rights in the PJM market or transmission congestion contracts in the

New York market – are hedges for the price risk due to congestion.

A CRR entitles its owner to receive or provide a payment that is proportional to the price difference between two locations on the grid. One way of obtaining CRRs will be through auctions administered by the independent transmission provider. CRRs may also be bought with firm transmission reservations or allocated to users that funded the embedded cost of the grid.

The allocation of CRRs is one detail of SMD that is under special scrutiny and debate.

under the strategy of settling the full amount in the DAM would be \$2,500, \$1,000 less than previously calculated.

Because congestion can only be hedged in the DAM, the LSE's DAM-versus-BM exposure strategy would vary depending on the LSE's CRR portfolio. In this example, the LSE is better off settling the 20MW in the BM (by only scheduling 100MW in the DAM) if the LSE does not have the CRR to hedge congestion risk in the DAM.

Long-term contracts

For this hour, the forward bilateral contract has saved the LSE \$4,000/hour on average, since the contract price of \$20/MWh is well

the SMD, the analysis of bilateral forward contracts, the value of CRRs and the assessment of bidding strategies all require a detailed knowledge of LMP outcomes. Analysis makes use of traditional statistical models and also requires power network models that represent grid operations. Congestion has the potential to cause greater price variation in spot markets, and risk management must address this factor.

The SMD will provide market participants with a number of markets and products for managing price risks with different time horizons. Firms will need to determine how much to hedge in the DAM and BM, consider congestion as well as price volatility in valuing long-term contracts, and decide how much to hedge their basis risk using CRRs.

Appropriate use of such market products will ensure LSEs and generators are implementing procurement and hedging decisions using sound risk management principles. [EPRM](#)

Ferc's proposed standard market design will provide market participants with a number of markets and products for managing price risks with different time horizons

CRR and \$7,500 if it does not. So, assuming the LSE has a CRR, the expected cost to serve load is no better than under the pre-SMD market. However, the variability has been reduced.

We should also bear in mind that while the CRR was from company A to the LSE, the LSE would prefer to hold the CRR from company A to company B, which is the most valuable CRR for this hour – worth \$200/MWh during the congested periods. If the LSE held 50MW of the CRR from company A to company B instead of 100MW of the CRR from company A to the LSE, the expected cost to serve load for that hour

below the mean LSE LMP of \$60/MWh. In the same manner, the contract appears to have cost company A \$2,000/hour based on the average LMP at company A of \$40/MWh for this hour. The decision to enter long-term contracts requires risk assessment over many time horizons, not a single hour. Assuming that the contract covers many hours, its performance over one hour is not indicative of a bad decision on company A's part.

Strategic considerations

Our case study illustrates a number of strategic considerations, but is not intended to indicate general trends. Under

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