Issues Raised in FSP Presentations by MISO, PJM and Their IMMs

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Topics

- Assessing Different Approaches for Setting LMPs
- Relaxing Integer Constraints for FSG Commitment Variables
- Permitting Offers from Offline FSGs to Set Prices

Assessing Different Approaches for Setting LMPs

Nonconvexities

- Procedures for setting prices in electricity markets must be able to accommodate nonconvexities. Some examples of nonconvexities include:
  - Start-up costs.
  - Minimum operating levels (Pmin).
  - Minimum up times.
  - Costs to operate at lower output levels that are higher than costs to operate at higher output levels.

Market Clearing with No Nonconvexities

- When there are no nonconvexities, it should always be possible to find a price that clears the market—in other words, which sets supply equal to demand.
  - All generating capacity that was offered at a price that is less than the LMP will be dispatched.
    - Thus, no generator would incur any lost opportunity costs (LOCs) because all undispatched capacity would have been offered at a price greater than or equal to the LMP.
  - No generating capacity that was offered at a price that exceeds the LMP will be dispatched.
    - Thus, no generator would require a bid cost recovery (BCR) payment to ensure that its revenue covers the cost at which it offered to produce the energy it was dispatched to produce.

Market Clearing with Nonconvexities

- Even when there are nonconvexities, it may nevertheless be possible to find a price that will clear the market.
  - At such a price, no generator would incur any LOCs, nor would any BCR payments be needed.
  - Some of the proposed procedures for implementing fast-start pricing (FSP) would produce an LMP that does not clear the market, even when it is possible to find an LMP that would clear the market.
  - This would produce inefficient incentives.

Example: An LMP Clears the Market

- Consider the following example.
  - G1 operates at its Pmax, 500 MW, and the fast-start generator (FSG) produces the remaining 175 MW that are needed to meet load.
  - An LMP of $80/MWh, which is the LMP that would be determined without using FSP, clears the market, as generators would supply anywhere from 650 MW to 700 MW at that LMP.
  - At that LMP, no generators incur any LOCs, nor are any BCR payments needed.

	Capacity (MW)	Offer ($/MWh)	Schedule (MW)	Bid Cost ($)
G1	500	$ 35.00	500	$ 17,500
G2	500	$ 110.00	-	$ -
FSG:				
Pmin	100		100	$ 7,000
Inc 1	50	$ 40.00	50	$ 2,000
Inc 2	50	$ 80.00	25	$ 2,000
Total			**675**	**$ 28,500**

Constant Adder Approach

- If the constant adder approach was used to determine the modified offer for the FSG that would be used in the pricing dispatch to determine the LMP:
  - The adder would be $7000 / 200 MWh = $35/MWh.
  - The LMP would be $110/MWh, since G2 would be on the margin in the pricing dispatch (even though it does not actually operate).

	Capacity (MW)	Actual Offer ($/MWh)	Modified Offer ($/MWh)	Pricing Schedule (MW)
G1	500	$ 35.00	$ 35.00	500
G2	500	$ 110.00	$ 110.00	25
FSG:				
Pmin	100		$ 75.00	100
Inc 1	50	$ 40.00	$ 75.00	50
Inc 2	50	$ 80.00	$ 115.00	-
Total				**675**

Adjusted Constant Adder Approach

- If the adjusted constant adder approach was used to determine the modified offer for the FSG that would be used in the pricing dispatch to determine the LMP:
  - The adder would be $7000 – ($40/MWh × 100 MWh) / 200 MWh = $15/MWh.
  - The LMP would be $95/MWh. While the Inc 2 block is on the margin, just as in the actual dispatch, the modified offer differs from the actual offer.

	Capacity (MW)	Actual Offer ($/MWh)	Modified Offer ($/MWh)	Pricing Schedule (MW)
G1	500	$ 35.00	$ 35.00	500
G2	500	$ 110.00	$ 110.00	-
FSG:				
Pmin	100		$ 55.00	100
Inc 1	50	$ 40.00	$ 55.00	50
Inc 2	50	$ 80.00	$ 95.00	25
Total				**675**

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LOCs When the Price Doesn't Clear the Market

- At an LMP of either \$110/MWh or \$95/MWh, there will be LOCs.
  - The FSG offered energy at \$80/MWh that was not dispatched.
  - At any LMP that is above \$80/MWh, it will be better off if it had been dispatched above its actual dispatch level of 175 MW.

	Capacity (MW)	Offer (\$/MWh)	Schedule (MW)	Bid Cost (\$)
G1	500	\$ 35.00	500	\$ 17,500
G2	500	\$ 110.00	-	\$ -
FSG:				
Pmin	100		100	\$ 7,000
Inc 1	50	\$ 40.00	50	\$ 2,000
Inc 2	50	\$ 80.00	25	\$ 2,000
Total			**675**	**\$ 28,500**

Incentives for Inefficient Actions

- Setting prices at levels that don't clear the market can provide an incentive for inefficient behavior.
  - When generators incur LOCs, if they are not paid for the foregone profits, they have incentives to bid something other than their actual cost structure to increase the amount of energy they are dispatched to produce.
  - That will be inefficient.
  - Thus, LMPs that are calculated in this manner will give generators an incentive to offer their capacity in a manner that undermines the ISO's objective of meeting load at the least cost.

Minimum Average Cost Approach

- In contrast, the minimum average cost ("MAC") approach for determining the modified offer for the FSG produces an \$80/MWh LMP in this example.
  - The modified offer is \$60/MWh for output up to 150 MW, because the average cost is minimized at (\$7000 + 50 MWh × \$40/MWh) / 150 MWh = \$60/MWh.
  - Above 150 MW, the modified offer is \$80/MWh, the same as the actual offer.
- Therefore, when the Inc 2 block is on the margin, the LMP is set by that block's actual offer.

	Capacity (MW)	Actual Offer (\$/MWh)	Modified Offer (\$/MWh)	Pricing Schedule (MW)
G1	500	\$ 35.00	\$ 35.00	500
G2	500	\$ 110.00	\$ 110.00	-
FSG:				
Pmin	100		\$ 60.00	100
Inc 1	50	\$ 40.00	\$ 60.00	50
Inc 2	50	\$ 80.00	\$ 80.00	25
Total				**675**

No Market-Clearing Price

- However, when there are nonconvexities, it may not be possible to find a price that will clear the market.
  - Consequently, either one or more generators will incur LOCs, or one or more generators may require BCR payments (or both).
  - Both LOCs and BCR payments may provide incentives for inefficient behavior.
- This is an inescapable consequence of nonconvexities. It will happen to some extent, whether FSP is adopted or not.
  - But the procedure for setting prices still can have a significant impact on the size of the LOCs and BCR payments, and the associated incentives for inefficient behavior.

Example: No LMP Clears the Market

- Consider the following example.
  - Load decreases to 625 MW, and the FSG's Pmin increases.
  - As a result, G1 operates at 25 MW below its Pmax of 500 MW, while the FSG operates at its Pmin of 150 MW.

	Capacity (MW)	Offer ($/MWh)	Schedule (MW)	Bid Cost ($)
G1	500	$ 35.00	475	$ 16,625
G2	500	$ 70.00	-	$ -
FSG:				
Pmin	150		150	$ 9,000
Inc	50	$ 80.00	-	$ -
Total			**625**	**$ 25,625**

Example: No LMP Clears the Market (cont'd)

- There is no LMP that will clear the market—in other words, that will set the amount supplied equal to the demand of 625 MW.
  - At any price from $35/MWh to $59.99/MWh, G1 is willing to supply 500 MW.
  - When the price reaches $60/MWh, the FSG becomes willing to provide 150 MW, so total supply leaps to 650 MW.
- As a result, there will be either LOCs or BCR payments.

	Capacity (MW)	Offer ($/MWh)	Schedule (MW)	Bid Cost ($)
G1	500	$ 35.00	475	$ 16,625
G2	500	$ 70.00	-	$ -
FSG:				
Pmin	150		150	$ 9,000
Inc	50	$ 80.00	-	$ -
Total			**625**	**$ 25,625**

Setting the LMP Using FSP

- If FSP is used (and the modified offer curve is set using the MAC approach), the LMP will be $60/MWh.
  - With the Pmin relaxed, the FSG is on the margin in the pricing dispatch.
  - But it is operating at a level that is less than 150 MW (the output level that minimizes its average cost).
  - Thus, the LMP is $60/MWh.

	Capacity (MW)	Actual Offer ($/MWh)	Modified Offer ($/MWh)	Pricing Schedule (MW)
G1	500	$ 35.00	$ 35.00	500
G2	500	$ 70.00	$ 70.00	-
FSG:				
Pmin	150		$ 60.00	125
Inc	50	$ 80.00	$ 80.00	-
Total				**625**

LOCs Resulting from the FSP LMP

- This LMP, $60/MWh, does not clear the market.
  - It is just high enough so that no BCR payments are needed.
  - But G1 incurs an LOC. Its offer is less than the LMP, so it would be better off if it had been dispatched to operate at Pmax.
  - As discussed earlier, if generators in such situations do not receive LOC payments, they will have incentives to modify their offer to increase their dispatch levels.

	Capacity (MW)	Offer ($/MWh)	Schedule (MW)	Bid Cost ($)
G1	500	$ 35.00	475	$ 16,625
G2	500	$ 70.00	-	$ -
FSG:				
Pmin	150		150	$ 9,000
Inc	50	$ 80.00	-	$ -
Total			**625**	**$ 25,625**

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Setting the LMP Without Using FSP

- If FSP is not used, the LMP would be G1's offer of $35/MWh.
  - There are no LOCs at this LMP, as G1 does not have an incentive to increase its output.
  - But the FSG would require a large BCR payment. The LMP is only $35/MWh, while its average cost is $60/MWh, so it would be paid $25/MWh × 150 MWh = $3750.

	Capacity (MW)	Offer ($/MWh)	Schedule (MW)	Bid Cost ($)
G1	500	$ 35.00	475	$ 16,625
G2	500	$ 70.00	-	$ -
FSG:				
Pmin	150		150	$ 9,000
Inc	50	$ 80.00	-	$ -
Total			**625**	**$ 25,625**

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Price Discrimination

- Effectively, this means that two different prices are being used for settlement.
  - G1 receives $35/MWh while the FSG receives $60/MWh, once the $25/MWh BCR payment is included.
- Systems that pay two different prices provide an incentive for generators to seek ways to be paid the higher price.
  - In this example, G1 has an incentive to increase its offer to $60/MWh, which would increase the LMP without affecting the amount of energy it is dispatched to produce.

Pay-As-Bid Incentives

- This recalls a debate concerning the fundamentals of market design.
  - If generators are paid a market-clearing price, they have an incentive to submit bids that reflect their actual cost structure (unless they are attempting to exercise market power).
  - If generators are paid what they bid, they have an incentive to submit bids that reflect their estimates of the marginal cost of meeting load, even if they are not attempting to exercise market power.
    - That will be inefficient, because generators that should operate sometimes would not be dispatched.
    - And it frustrates attempts to assess whether bids are consistent with competitive behavior.

Pay-as-Bid Incentives and FSP

- Whenever there are BCR payments, there are aspects of a pay-as-bid system, because some generators are paid a different price than others.
  - But these concerns can be much more significant in cases like this if FSP is not used.
  - Not using FSP will increase the gap between the prices that different generators are paid, increasing the incentive to submit bids that do not reflect costs.

Another Example with No Market-Clearing Price

- Finally, consider the following example.
  - Load remains 625 MW, but the FSG's Pmin returns to 100 MW.
  - As a result, G1 can now operate at its Pmax of 500 MW, while the FSG operates at 125 MW.

	Capacity (MW)	Offer ($/MWh)	Schedule (MW)	Bid Cost ($)
G1	500	$ 35.00	500	$ 17,500
G2	500	$ 110.00	-	$ -
FSG:				
Pmin	100		100	$ 7,000
Inc 1	50	$ 40.00	25	$ 1,000
Inc 2	50	$ 80.00	-	$ -
Total			**625**	**$ 25,500**

Setting the LMP Without Using FSP

- If FSP is not used, the LMP would be \$40/MWh, the offer of the FSG's Inc 1 block.
  - There would be no LOCs, but the FSG would require a large BCR payment.
    - The FSG's average cost is \$8000 / 125 MWh = \$64/MWh.
    - So, its BCR payment would be (\$64/MWh – \$40/MWh) × 125 MWh = \$3000.
  - This gives G1 a strong incentive to take actions to increase its revenue.

	Capacity (MW)	Offer (\$/MWh)	Schedule (MW)	Bid Cost (\$)
G1	500	\$ 35.00	500	\$ 17,500
G2	500	\$ 110.00	-	\$ -
FSG:				
Pmin	100		100	\$ 7,000
Inc 1	50	\$ 40.00	25	\$ 1,000
Inc 2	50	\$ 80.00	-	\$ -
Total			**625**	**\$ 25,500**

Setting the LMP Using FSP

- If FSP is used (under the MAC approach for defining the modified offer), the LMP would be $60/MWh, for the same reason as in the previous example.
  - Once more, there would be no LOCs.
  - The FSG would require a BCR payment, but it would be only $8000 – $60/MWh × 125 MWh = $500, not $3000.
  - The incentive for G1 to take actions to increase its revenue is much lower.

	Capacity (MW)	Actual Offer ($/MWh)	Modified Offer ($/MWh)	Pricing Schedule (MW)
G1	500	$ 35.00	$ 35.00	500
G2	500	$ 110.00	$ 110.00	-
FSG:				
Pmin	100		$ 60.00	100
Inc 1	50	$ 40.00	$ 60.00	25
Inc 2	50	$ 80.00	$ 80.00	-
Total				**625**

Comparing the LMPs

- In this example, I think it is clear that $60/MWh is the more appropriate LMP.
  - Lower LMPs increase BCR payments and incentives for other generators to increase their offers.
  - An LMP above $60/MWh would reduce the BCR—but it would lead to LOCs, because the FSG would prefer to operate at 150 MW.

Relaxing Integer Constraints for FSG Commitment Variables

Relaxing Integer Constraints

- In the physical dispatch, commitment variables for each resource are set to 0 (not committed) or 1 (committed).
- Instead of constructing a modified offer curve and using it in the pricing dispatch to determine the LMP under FSP, an alternative is to relax the requirement for this variable to be an integer for FSGs in the pricing dispatch.
  - PJM and MISO both use this approach.
- For example, if the value of the FSG commitment variable was 0.5:
  - Half of the start-up and minimum load costs would be incurred.
  - The FSG could be dispatched between half of its actual Pmin and half of its actual Pmax.

Setting the LMP with Partial Unit Commitment

- In the preceding examples, when the load was 625 MW, this approach produces an LMP of $60/MWh.
  - That is the same as the LMP produced using the modified offer curve (under the MAC approach).
- The value of the FSG commitment variable is 5/6, which permits the generator to produce 125 MW at its modified Pmin.
  - Meeting another MWh of load would require the commitment variable to increase to 0.84, since 0.84 × 150 MW = 126 MW.
  - The cost of increasing the value of the FSG commitment variable is (0.84 – 0.8333) × $9000 = $60, so the LMP is $60/MWh.

	Capacity (MW)	Offer ($/MWh)	Mod. Capacity (MW)	Pricing Schedule (MW)
G1	500	$ 35.00	500.00	500.00
G2	500	$ 70.00	500.00	-
FSG:				
Pmin	150		125.00	125.00
Inc	50	$ 80.00	41.67	-
Total				**625.00**

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Setting the LMP with Full Unit Commitment

- When load increases to 675 MW, and the FSG is dispatched above its cost-minimizing output level, the commitment variable in the pricing pass is 1, even though the integer constraint has been relaxed.
- In that case, the LMP is set using the $80/MWh offer that was actually submitted for the dispatchable segment of the FSG.
- The $80/MWh price is the same price that would be produced if FSP is not used, or if FSP is used but the MAC approach is used to determine the modified offer.

	Capacity (MW)	Offer ($/MWh)	Mod. Capacity (MW)	Pricing Schedule (MW)
G1	500	$ 35.00	500.0	500.00
G2	500	$ 70.00	500.0	-
FSG:				
Pmin	150		150.00	150.00
Inc	50	$ 80.00	50.00	25.00
Total				**675.00**

Example with Operating Reserve

- But in examples with operating reserve ("OR"), these two approaches to FSP can produce different results.
  - The example below shows a least-cost dispatch to meet 575 MW of load while also maintaining at least 30 MW of OR.
  - The decrease in load means that G1 needs to be backed down even further, to 425 MW.
  - G1 is scheduled to provide OR, but the other generators also could have provided it.

	Capacity (MW)	Offer ($/MWh)	Energy Schedule (MW)	OR Schedule (MW)	Bid Cost ($)
G1	500	$ 42.00	425	30	$ 17,850
G2	500	$ 80.00	-	-	$ -
FSG:					
Pmin	150		150	-	$ 9,000
Inc	50	$ 80.00	-	-	$ -
Total			**575**	**30**	**$ 26,850**

Setting Prices Using Modified Offers

- If FSP is implemented using the modified offer approach, with the modified offer curve developed using the MAC method, the LMP would once again be $60/MWh.
- The price of OR would be $0/MWh, since an increase in the OR requirement would not increase the cost of the dispatch.

	Capacity (MW)	Actual Offer ($/MWh)	Modified Offer ($/MWh)	Pricing Pass Energy Sch. (MW)	Pricing Pass OR Sch. (MW)
G1	500	$ 42.00	$ 42.00	500	-
G2	500	$ 80.00	$ 80.00	-	-
FSG:					
Pmin	150		$ 60.00	75	30
Inc	50	$ 80.00	$ 80.00	-	-
Total				**575**	**30**

Setting Prices by Relaxing the Integer Constraint

- If FSP is implemented by relaxing the integer constraint for the FSG commitment variable in the pricing dispatch:
  - An additional MWh of load would be met by increasing the value of the FSG commitment variable from 0.525 to 0.53, while also dispatching G1 up by 0.25 MW. The LMP is (0.53 – 0.525) × \$9000 + 0.25 × \$42/MWh = \$55.50/MWh.
  - An increase of 1 MW in the OR requirement would be met by increasing the value of the FSG commitment variable from 0.525 to 0.53, and dispatching G1 down by 0.75 MW. The LMP is (0.53 – 0.525) × \$9000 – 0.75 × \$42/MWh = \$13.50/MWh.

	Capacity (MW)	Offer (\$/MWh)	Mod. Capacity (MW)	Pricing Pass Energy Sch. (MW)	Pricing Pass OR Sch. (MW)
G1	500	\$ 42.00	500.0	496.25	3.75
G2	500	\$ 80.00	500.0	-	-
FSG:					
Pmin	150		78.75	78.75	-
Inc	50	\$ 80.00	26.25	-	26.25
Total				**575.00**	**30.00**

LOCs and BCR Payments

- Neither of these sets of prices will clear markets.
  - The modified offer approach to FSP will not lead to any BCR payments, but G1 would incur LOCs of 75 MWh × ($60/MWh – $42/MWh) = $1350, as it would prefer to generate 500 MWh at a $60/MWh LMP.
  - The integer constraint relaxation approach to FSP will necessitate BCR payments of $9000 – 150 × $55.50/MWh = $675 for the FSG.
  - It will also lead to LOCs of 45 MWh × ($55.50/MWh – $42/MWh) = $607.50 for G1 and 500 MWh × $13/MWh = $6750 for G2.

	Capacity (MW)	Offer ($/MWh)	Energy Schedule (MW)	OR Schedule (MW)	Bid Cost ($)
G1	500	$ 42.00	425	30	$ 17,850
G2	500	$ 80.00	-	-	$ -
FSG:					
Pmin	150		150	-	$ 9,000
Inc	50	$ 80.00	-	-	$ -
Total			**575**	**30**	**$ 26,850**

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OR Pricing Under Integer Constraint Relaxation

- These LOCs illustrate a concern about the integer constraint relaxation approach.
  - The price of OR is positive because this approach only commits enough capacity in this example to meet load and the OR requirement.
  - Increasing the OR requirement therefore requires an increase in the value of the FSG commitment variable, at a cost.

	Capacity (MW)	Offer ($/MWh)	Mod. Capacity (MW)	Pricing Pass Energy Sch. (MW)	Pricing Pass OR Sch. (MW)
G1	500	$ 42.00	500.0	496.25	3.75
G2	500	$ 80.00	500.0	-	-
FSG:					
Pmin	150		78.75	78.75	-
Inc	50	$ 80.00	26.25	-	26.25
Total				**575.00**	**30.00**

Impact of OR Pricing on Incentives

- But, as the dispatch below shows, there is plenty of capacity on all three generators that can provide OR.
- If generators are not paid for LOCs, they will have incentives to take actions that would increase the likelihood they are scheduled to provide OR, which could be inefficient.
- The alternative is to pay for LOCs, but those costs could be large, as in this example.

	Capacity (MW)	Offer ($/MWh)	Energy Schedule (MW)	OR Schedule (MW)	Bid Cost ($)
G1	500	$ 42.00	425	30	$ 17,850
G2	500	$ 80.00	-	-	$ -
FSG:					
Pmin	150		150	-	$ 9,000
Inc	50	$ 80.00	-	-	$ -
Total			**575**	**30**	**$ 26,850**

Permitting Offers from Offline FSGs to Set Prices

Impact of Considering Offline FSGs

- In some ISOs/RTOs, FSGs that are offline, but can be started quickly, are considered in the pricing dispatch that is used to set LMPs.
  - This can limit price spikes that arise when it would not be efficient to start an FSG because only a small portion of its Pmin is needed.

Potential for High LMPs

- In the example below, the FSG is not scheduled to start because its Pmin is 100 MW, but only 5 MW of that energy is needed, after accounting for the energy G1 can produce.
  - G1 would have to be backed down by 95 MW to accommodate the remainder of the FSG's output at Pmin.
  - Thus, it is cheaper to dispatch G2, even though it is very expensive, because it can produce just 5 MW.
- If the offline FSG's offers are not considered in price-setting, the LMP under FSP would be $500/MWh.
  - Even higher prices would be possible in other examples.
- But if the FSG's offers are considered, the LMP will be $60/MWh.

	Pmax (MW)	Pmin (MW)	Offer ($/MWh)	Schedule (MW)	Bid Cost ($)
G1	500	-	$ 35.00	500	$ 17,500
G2	100	-	$ 500.00	5	$ 2,500
FSG (offline)	100	100	$ 60.00	-	$ -
Total				**505**	**$ 20,000**

Prices Fall When Load Increases

- If the load were to increase slightly, to 510 MW, the FSG would be started, even though doing so requires backing G1 down to 410 MW.
- Then the price, under FSP, would fall to $60/MWh.
- Thus, if offline FSGs are not permitted to participate in FSP, unusual price patterns like this may sometimes occur, which might affect the value of the LMP as a price signal.

	Pmax (MW)	Pmin (MW)	Offer ($/MWh)	Schedule (MW)	Bid Cost ($)
G1	500	-	$ 35.00	410	$ 14,350
G2	500	-	$ 500.00	-	$ -
FSG	100	100	$ 60.00	100	$ 6,000
Total				**510**	**$ 20,350**

Incentives for Mitigating Spikes

- But permitting offline FSGs' offers to be considered in price setting will undermine the incentives for developing resources that could mitigate those short-term spikes.
- In this case, if there was a battery available to operate at $100/MWh, it could run instead of G2.
- But letting the offline FSG's offers participate in price setting effectively caps the price at $60/MWh, thereby muting the market incentives for the development of that battery.

	Pmax (MW)	Pmin (MW)	Offer ($/MWh)	Schedule (MW)	Bid Cost ($)
G1	500	-	$ 35.00	500	$ 17,500
G2	100	-	$ 100.00	5	$ 500
FSG (offline)	100	100	$ 60.00	-	$ -
Total				**505**	**$ 18,000**

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