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Options for State Funded Energy Efficiency Programs in the Forward Capacity Market

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Introduction

As a result of a settlement agreement approved by the Federal Energy Regulatory Commission, ISO New England is developing and will soon administer a Forward Capacity Market (FCM) for New England.

One innovative feature of the FCM is that, for the first time, Demand Resources will be able to bid into the market on an equal basis as Supply Resources. As a result, Demand Resources will become eligible to receive capacity payments at a price decided in a yearly auction. From a wholesale markets perspective, the decision to invest in a 10 MW energy efficiency program will be on equal financial footing with a 10 MW combustion turbine.

Because the FCM is a three-year forward auction, the settlement agreement also describes a Transition Period that starts in December of this year, and ends on May 31, 2010, one day before the start of the first Commitment Year of the FCM. During this Transition Period, all qualified capacity in New England, including Demand Resources, can receive capacity payments. The amounts of these payments were negotiated in the settlement. They start at $3.05/kW-month and grow to $4.10/kW-month.

The FCM creates a potential new revenue stream for utility DSM programs. It also creates many new decisions for regulators regarding how programs should participate in the market and how the resulting revenues should be used. This paper is designed to provide background and to set forth some of the options for regulators and program administrators.

The FCM

Capacity Market

In the FCM, capacity is purchased three years in advance of the obligation to deliver. This three-year period is intended to allow a developer sufficient time to complete any projects that clear in the auction, and it reduces the risk involved with developing new capacity.

The amount of capacity purchased in the auction is called the Installed Capacity Requirement (ICR). The major portion of ICR is the ISO's forecast of peak loads, but it also includes adjustments for reserves, tie benefits, relief provided by OP4 actions, and other factors. It is easiest to think of ICR as simply the forecasted peak load plus reserves.

Sellers and Buyers

All capacity sellers that clear in the FCM will receive payments in the delivery year based upon a single clearing price set in the auction. Those receiving payments have a number of obligations, of course. They must commit to provide capacity for an entire year (new resources can choose a longer commitment), and most resources must be available during Shortage Hours or else they will be assessed availability penalties. However, because supply will meet demand at all times, any availability penalties will be distributed to those resources that overproduced during these Shortage Hours. Simply put, those who fail to meet their obligations will pay those who cover for them. The net cost to buyers (load) does not change when sellers are penalized for lack of availability.

Interaction with the Energy Market

The primary obligation of a capacity resource is the requirement to offer into the energy market on a daily basis. During high-priced hours, all online generators will receive revenues large enough to offset not only their variable costs, but a good portion of their fixed costs as well. In order to assure that these generators, who are receiving capacity payments, will not earn windfalls during high-priced hours, they will be assessed a Peak Energy Rent (PER) deduction against those capacity payments. The amount is based upon the revenue requirements of a hypothetical peaking unit and, at today's natural gas prices, the threshold price is roughly $155/MWh. Energy revenues that a capacity resource would receive at prices above this amount will be deducted from their capacity payments.[1]

The PER deduction may vary widely: it will be higher in hot summers or cold winters and lower in mild weather when there are fewer high-priced hours. The important consideration is that, unlike availability penalties which merely shift money around amongst generators, ***PER deductions reduce the overall capacity cost paid by load.***

[1] The ISO will deduct from the capacity revenues of all listed generating resources the amount of energy revenues that this hypothetical gas turbine would receive.

Although PER deductions are straight dollar amounts, the ISO will formulate them in terms of an adjustment to the capacity price. If the clearing price in the auction was $6.00/kW-month we might estimate that all of the PER deductions in the upcoming commitment year will reduce that price by, say, $1.00/kW-month. The resulting net cost of capacity is now $5.00/kW-month. This is the price of capacity paid to sellers, and paid by the buyers.

Capacity buyers are Load Serving Entities (LSEs) in the region. All LSEs are assessed a share of the region's capacity obligation based upon the load recorded at their customers' meters during the peak hour in the most recent summer. This share is called its Peak Load Ratio Share. For example, if an LSE was serving 2,800 MW of load on August 2nd of this year, it would have a peak load ratio share of 10% (2,800 MW divided by a peak load for the summer of 28,000 MW). If next year's ICR is 31,000 MW, this LSE would have a capacity obligation of 10% of 31,000 MW, or 3,100 MW.

Along with the price of capacity, it is this capacity obligation that determines the total cost of capacity for each LSE. In our example, this LSE would pay 3,100 MW x $5.00/kW-month, or $15,500,000/month.[2]

Financial Options for Participation of DSM Programs

Those LSEs who administer DSM programs (LSE-PAs) will have options as to how to use these savings to either offset capacity costs or receive capacity payments. They can use their programs as Self Supplied Capacity, as Capacity Offered in the Auction, or perhaps as "Stealth" DSM.

It should be noted that in the existing monthly capacity auction (the ICAP Market) LSE-PAs have only one option: to reduce ICR. The LSE-PAs can notify the ISO of their current and future program levels and the ISO will reduce the ***region's*** ICR accordingly. However, in the FCM LSE-PAs will have the option to use their DSM programs as self-supplied capacity, which reduces their ***individual*** capacity obligation. In the FCM, it is assumed that any LSE-PA wishing to reduce their obligation will do so via the self-supply option, rather than reducing the whole region's ICR.

Self Supplied Capacity

Under the FCM rules, all LSEs have the option of supplying their own capacity. That is, instead of purchasing the entirety of their capacity obligation via the auction, an LSE may – at its discretion – choose to offset some or all of this obligation with capacity that it owns. Traditionally, the option to self-supply has been used by municipal utilities because they own generation resources. However, now this option is also available to any LSE who can meet some of its capacity obligation with Demand Resources.

[2] The cost of capacity for any LSE will be its peak load ratio share percentage of the region's capacity cost. In reality, the region's capacity cost will be a blend of a number of factors, including results from one or more primary auctions and many annual, seasonal, and monthly reconfiguration auctions. We have simplified the calculation here for ease of explanation. We use the same example in all three options, so the effect is the same.

The most critical problem is that this approach only reduces capacity costs at the net capacity price. If the auction clears at $6.00/kW-month and the PER deduction is $1.00/kW-month, the effective price for capacity becomes $5.00/kW-month. If this DSM program will reduce peak load by 10 MW and therefore avoid 10 MW of capacity obligation, the LSE will save $50,000 per month.[3]

We note here that in the FCM, all suppliers of Demand Resources into the auction – whether as self supply or as capacity offered - will be required to submit qualification packages, M&V plans, reference updates, and monthly reports to the ISO. The M&V plans required by the ISO will be consistent with existing state reporting requirements. There will, of course, be some finite transaction cost associated with these activities.

Capacity Offered in the Auction

The second option, and the one envisioned by the Settlement Agreement, is for Demand Resources to offer their capacity in the auction, just as traditional capacity might. An ESCo or program administrator can offer price-quantity pairs into the auction or choose to delist (i.e., remove its resource from the market). Their offer even has the opportunity to set the clearing price in the auction.

But there's a key difference. Generators are required to submit daily energy offers into the Day Ahead and Real Time energy markets and are subject to PER deductions in those hours when prices are high. Because Demand Resources do not receive any energy market revenues, they are not assessed this deduction. This is worth restating. ***Demand Resources are not assessed a PER deduction.***

Given this difference, there is a financial advantage to offering Demand Resources in the auction rather than using them for self-supply. Consider again our example of a program that produces 10 MW of capacity reduction. Under the self-supply option, the LSE-PA avoids buying 10 MW of capacity at a savings of $50,000 per month (10 MW * $5.00/kW-month ($6.00/kW-month clearing price less $1.00/kW month PER deduction)). However, that same 10 MW bid into the auction generates $60,000 per month (10 MW * $6.00/kW month clearing price with no PER deduction). The difference is $10,000 per month or 20%.

Bidding Demand Resources into the auction has the additional advantage of generating a clear revenue stream that can easily be directed to benefit all customers that contributed to funding the programs. This approach avoids the complications that self-supply encounters in most New England states, given the utilities' roles as Program Administrators for all customers but LSEs for only some (default service customers).

Stealth DSM

Some have suggested that regulated utilities will also have the option of keeping their DSM programs out of the market altogether – offering them neither as self-supply nor as bid resources – yet still reduce their capacity costs as a result of program reductions in peak demand. We have termed this option Stealth DSM.

[3] See footnote 2, above

Under this approach, the program administrator would invest the public benefit funds as efficiently as possible and maximize the impact of those monies, as always. However, no notification would be given to the ISO of the level or progress of these efforts. Neither the ISO's planning department nor their regional forecasters would have any knowledge of these programs and would not account for them in their activities. The effects of these programs would only be accounted for in the actual meter data.

There are a number of problems with this approach. First, the FCM is a three-year forward market. Capacity is purchased in an auction three years in advance of a delivery year. The amount of capacity purchased in that auction is the amount that the ISO has forecasted to be needed to meet system reliability, the ICR. Accordingly, there would be a three year lag between any stealth DSM activity and the time this change is reflected in the ICR. As a result, in any year when program funding levels increase the region will buy too much capacity for three years.

Second, no matter the level of funding for these DSM programs, there would be a three year lag for the first auction because these programs have historically been a piece of the ICR calculation. If a program administrator now tells the ISO to ignore any effects of the DSM programs, the ISO will be forced to increase the ICR by the amount of the programs' savings. In three years, this amount will be rolled into meter data and therefore into the ISO forecasts, but until then the region will buy more capacity than it needs. Ratepayers will pay too much for at least three years.

Further, like self-supply, this approach only avoids the net capacity price (clearing price minus PER), not the full clearing price. If the auction clears at $6.00/kW-month and the PER deduction is $1.00/kW-month, the effective price for capacity becomes $5.00/kW-month. If this DSM program will reduce peak load by 10 MW, the utility will save $50,000 per month, once the 10 MWs show up in metered loads. This LSE will only save $5.00/kW-month, not the full $6.00 clearing price.

Finally, a significant percentage of the savings due to Stealth DSM would be captured by competitive suppliers rather than the utility Program Administrator. The utility, in its role as LSE for default service customers, would capture the Stealth DSM savings attributable to default service customer participation in DSM programs. However, the savings attributable to competitive supply customers that participate in DSM programs would flow to those competitive suppliers. Given that many utilities have 50% of their load on competitive supply, this is a very significant effect.

The only benefit to be derived from the Stealth DSM approach would be a reduction in reporting requirements. Using either of the other approaches, the ISO will require some proof that the DSM programs being promised at the time of the auction will be delivered in the commitment year. This will come in the form of annual M&V plans similar to those already submitted to state regulators, monthly reports to verify continued performance aligned with the M&V plan, and some amount of financial assurance. However, it is expected that the extra effort required to submit annual plans and monthly reports will be minimal. Choosing the Stealth DSM option would avoid all of the ISO's reporting requirements, but would leave significant sums of money on the table as well.

Allocating the Benefits

Regardless of whether DSM programs participate in the FCM as Self-supplied Capacity, Capacity Offered in the Auction, or Stealth DSM, regulators will need to decide how to allocate the benefits that are created. Issues will include:

- **Shareholders or ratepayers?** Insofar as the benefits are created by programs funded by ratepayers, it would seem appropriate to direct the benefits to ratepayers rather than shareholders.[4]
- **Which ratepayers?** Insofar as the programs are funded through a charge paid by **all** ratepayers, it would seem appropriate to flow the benefits to **all** ratepayers rather than just a subset. There would be challenges applying this approach in a "self-supply" scenario because, in most New England states, the utilities serve as LSE for only some customers – those on default service. Absent a mechanism to spread the benefits to all customers, any savings that a utility realizes through "self-supply" of its default service obligations would flow just to default service customers (through lower default service prices) rather than to all customers.
- **Rate reductions or increased program budgets?** Regulators will also need to decide the form in which benefits are made available to customers. Options include (a) rate reductions and (b) increased program budgets. A strong advantage to the latter course is that it will create additional savings going forward.

Future Analysis

Proponents of the efficacy of utility DSM programs will want to ensure that these programs receive proper credit for their contribution to system reliability at the lowest possible cost. Regulators and LSE-PAs are very aware of the region's DSM programs, but many other market players are not. If DSM programs are offered into the auction as a capacity resource they become more visible to the ISO, other market players, and especially market analysts.

When auction results are published, having DSM programs and other Demand Resources listed alongside traditional generation will make it simpler and more effective to judge their contribution to, and effect on, this market. This impact will be diluted if DSM programs are used as self-supply, to avoid capacity obligation rather than fulfilling it.

Illustrative Example

It is helpful to consider the impacts of these three options with the use of an illustrative example. We have provided one such example in Figure 1, below. This table begins with a situation in which an LSE's peak load would have been 2,810 MW, but this LSE

[4] States that have adopted financial incentive mechanisms to reward program administrators for exemplary performance and to compensate them for risks assumed, may wish to consider making a portion of the FCM benefits available to program administrators under a similar mechanism.

has implemented 10 MW of DSM savings. Their peak load now becomes only 2,800 MW, and they have three capacity options – as described above - for these 10 MWs. There are a number of assumptions in Figure 1, most notably the Capacity Clearing Price and the PER Deduction. Of course these values will be different in reality but we believe that this figure provides a reasonable example.

Figure 1 - Sample Scenario to help in contrasting Options for DSM in the FCM

Stealth DSM	Self Supply	Offered in Capacity Auction	Description
2,810	2,810	2,810	Peak Load Before DSM (MW)
10	10	10	DSM conincident with peak hour
10	9	9	Capacity in wholesale market
0%	24%	24%	Peak T&D Losses and Reserve markups
10	11.16	11.16	Basis for capacity savings or payment (MW)
$ 6.00	$ 6.00	$ 6.00	Capacity Clearing Price ($/kW-month)
$ 1.00	$ 1.00	n/a	PER deduction ($/kW-month)
$ 5.00	$ 5.00	$ 6.00	Net capacity price ($/kW-month)
↓	↓	↓	
2,800	2,800	2,811	LSE peak load (MW)
28,000	28,000	28,011	System peak load (MW)
10.00%	10.00%	10.04%	Peak Load Ratio Share
31,000	30,989	31,000	ICR (MW)
3,100	3,099	3,111	Capacity Obligation (with ICR of 31,000 MW)
$ 15,500,000	$ 15,494,420	$ 15,555,579	Monthly Capacity Cost
$ -	$ -	$ 66,960	Monthly Capacity Revenues
$ 15,500,000	$ 15,494,420	$ 15,488,619	Net Monthly Capacity Cost
$ -	$ (5,580)	$ (11,381)	Difference from Stealth DSM
	$ (66,960)	$ (136,577)	Annualized difference