Market Incentives for Generation Investment

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I. INTRODUCTION

While an intended goal of the development of competitive electricity markets was increased reliance on market forces to incent investments in generation investments, many North American electricity markets, including the current Ontario market, have design features that cause spot market energy and ancillary service revenues to be insufficient to support generation investment, even when investment is necessary from a reliability perspective. While the inadequacy of spot energy market revenues from the standpoint of supporting generation investment arises from several interrelated market design elements, a fundamental problem is that current reliability standards are generally premised on a very small number of hours of reserve shortage during a typical year, requiring very high spot prices (typically somewhere in the range of $7,500 to $15,000 per megawatt hour) during these hours if the generation margins during these hours are to provide sufficient return on assets to encourage new generation investment. [2]

There is nothing intrinsically infeasible about an electricity market based on such high prices during a limited number of shortage hours, and some electricity markets around the world are premised on such a design. However, the potential for such high prices during a few hours of the year also gives rise to the potential for substantial wealth transfers from consumers to producers if consumers do not enter into forward contracts for power and the exercise of market power causes prices to rise to these high levels for more than the small number of reserve

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2 Peaking units have the lowest fixed costs to recover in energy margins but must recover these fixed costs in the small number of hours a year in which they are needed. Baseload units have lower variable costs and therefore earn larger energy margins than peaking units, but also have higher fixed costs to recover.

shortage hours on which reliability models are premised. All of the markets that are unable to support needed generation investments from energy market revenues share the characteristic of bid caps and or reserve shortage values that are set far below $7,500 per megawatt. These low bid cap levels reduce the potential for large wealth transfers arising from the exercise of market power during a small number of hours but also make it impossible for spot energy market revenues during a small number of reserve shortage hours to support the desired level of generation investment and reliability.

Given the need to supplement energy market revenues in order to sustain the generating capacity needed to maintain electric system reliability, several electricity market operators have entered into contracts to make supplemental payments to keep needed generation in operation, despite energy market revenues that are inadequate to cover their going-forward costs. These RMR contracts have been found, however, to have a number of undesirable features: they do not support new investment; they foreclose competition between high cost incumbents and potential lower cost generation entrants or demand response; and they are likely to spread over time, imposing a resource burden on regulators and requiring more and more reliance on non-market mechanisms to support needed generation.

Another widely used approach is the implementation of locational capacity markets. While this approach has generally come to be preferred over RMR contracts, and can support competition between incumbents and lower cost generation or demand response alternatives, the combination of low spot market energy prices and high capacity prices gives rise to a wide variety of short-run and long-run incentive problems and does not resolve the potential for the exercise of market power in the short-run.

The short-run potential for the exercise of market power can be addressed by consumers entering into forward contracts for power with new suppliers, and such forward contracts can insulate consumers from the consequences of the exercise of market power in either energy or capacity markets, as well as insulating consumers from short-term variations in spot market price levels that are due to changes in market fundamentals rather than the exercise of market power. Part of the generation investment problem in the U.S. markets having low bids caps in the energy market and having implemented capacity markets to support generation investment is the prevalence of retail access designs in which no entity has a long-term obligation to serve load and thus there are few long-term contracts hedging consumers from either the exercise of market power in energy or capacity markets or from adverse supply shocks that substantially raise equilibrium energy and/or capacity prices.

Another possible response to the generation investment problem has therefore been for a central entity to enter into long-term forward contracts for new capacity, while regulators continue to apply bid caps at levels that make the energy delivered under these contracts appear uneconomic. This process procures the level of capacity needed to maintain reliability, but requires financial support to the contracting entity in order to fund contract payments. Moreover, the low spot energy prices give rise to many of the same incentive problems associated with capacity markets. Conversely, however, if a central entity were to enter into long-term contracts that hedged consumers against the potential for the exercise of market power (as well as other variations in spot prices), then high shortage pricing values could be relied upon to set appropriately high prices during stressed system conditions, providing strong performance incentives for suppliers that have entered into such contracts, and for demand response providers. However, any centralized process that contracts forward for energy or capacity on behalf of customers runs the risk of contracting for energy or capacity that will not be demanded by consumers at the retail power price required to recover the contract costs.

All approaches to incenting the appropriate level of generation investment in a competitive market have limitations, but some approach or combination of approaches needs to be embraced and applied to maintain reliability.

II. INVESTMENT INCENTIVES AND ENERGY MARKET REVENUES

One intended goal of the development of competitive generation markets was increased reliance on market forces to incent investments in new generation resources. While energy and ancillary service revenues could, in principle, be relied on to incent such investments, a variety of structural/market design factors have combined to prevent this goal from being realized in most U.S. power markets and this has also been the case in Ontario. Instead, the margins generation resources earn in these competitive energy and ancillary service spot markets (either day-ahead or real-time) have typically been insufficient to incent generation investment, even when additional investment is warranted from a reliability perspective.[3] This relationship has generally prevailed in the competitive generation markets in the United States and currently prevails in Ontario as well. Because the cause of inadequacy of energy market revenues does not arise from the supply and demand balance (i.e., it does not arise from an excess of capacity relative to that required to meet current reliability criteria)[4] but rather is rooted in current institutions and market designs, the affected jurisdictions have either had to develop mechanisms other than incentives based on spot energy market revenues to ensure the construction of needed capacity in these markets, or take steps to address the causes of the inadequate energy and ancillary service margins.[5]

A. Adequacy of Energy Market Margins

There are a wide variety of resources that can provide the electrical energy needed to meet consumer load, each with varying investment costs, operating costs, environmental impacts, and operating characteristics. The discussion below highlights the general relationship between energy market margins and investment costs by comparing the energy market revenues and costs of a benchmark combined cycle unit and combustion turbine. These are generally reasonable benchmarks of the general level of investment incentives provided by energy market revenues because they continue to be the marginal generating resource in many regions, despite the current high level of gas prices. Moreover, use of these resources as benchmarks greatly facilitates comparisons across regions because the market monitors of all organized U.S. spot

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3 In the discussion below, we will use the expressions energy market revenues or margins to refer to the combination of payments for energy and the supply of ancillary services.

4 This takes existing reliability criteria as a given; a different reliability standard would likely require a different amount of capacity.

5 Causality is not one-way; while these mechanisms are necessary given the inadequacy of energy market revenues, the capacity supported by these other mechanisms can contribute to the inadequacy of energy market revenues from the standpoint of supporting generation investment.

markets routinely calculate spot energy market revenues for these benchmark units, as does the Market Surveillance Panel of the Ontario Energy Board.

PJM

Table 1 portrays the PJM Market Monitor's estimate of the energy and ancillary service market revenues of a benchmark combustion turbine and combined cycle unit for several illustrative utility service territories within PJM. These revenues averaged less than a third the estimated annualized fixed costs of the corresponding new units, so were by themselves insufficient to incent investment in the regions in which it was needed. Moreover, until 2007, new investment in combustion turbines or combined cycle units located within PJM was not economic based on spot energy market revenues, even with capacity market revenues taken into account.[6] This situation led to implementation of a new capacity market design (RPM) which provides additional revenues to supplement energy market margins.

Table 1
PJM Energy and Ancillary Service Revenues
($ per Megawatt)

		Standardized Combustion Turbine								
	2007	**2006**	**2005**	**2004**	**2003**	**2002**	**2001**	**2000**	**1999**	**Average**
Pepco	60,970	39,995	28,088	6,163	6,858	24,272	20,356	9,270	56,804	28,086
PSEG	34,559	18,174	19,129	15,411	6,803	15,747	29,066	12,419	58,519	23,314
PP&L	27,626	15,806	14,651	3,368	4,513	14,837	28,996	10,001	57,553	19,706
Com Ed	9,271	7,131	1,747							6,050
		Standardized Combined Cycle								
Pepco	**100007**	**44847**	**33290**	**14694**	**15568**	**38943**	**54471**	**32625**	**76635**	**45676**
PSEG	75,315	23,027	24,332	23,941	15,512	30,418	73,181	35,773	78,351	42,206
PP&L	38,837	20,658	19,854	11,899	13,223	29,508	63,111	33,356	77,384	34,203
Com Ed	22,636	14,177	10,757							15,857
Source PJM Market Monitoring Unit, 2007 State of the Market Report pp.124-129										

[6] PJM Market Monitoring Unit, 2007 State of the Market Report, pp. 122-143, located at http://www.pjm.com/markets/market-monitor/som.htm**.**

Under the locational RPM capacity market implemented in 2007, data compiled by PJM's independent market monitor indicate that total generator margins (from energy, ancillary services, and capacity revenues) rose during 2007 to roughly the level that if sustained over time would support new investment in gas turbines and combined cycle units in a number of eastern PJM zones (Atlantic Electric, Baltimore Gas & Electric, Delmarva Power & Light, Jersey Central Power & Light, Pepco, PSEG).[7] Spot energy and ancillary service revenues alone at the levels prevailing in 2007, however, would have been inadequate on an ongoing basis to support new investment in gas turbines or combined cycle units in any of these regions and would apparently have been inadequate by a fairly wide margin in all but the Baltimore Gas & Electric and Pepco zones.[8]

New York

While new investment in combustion turbines and combined cycles has been economic in New York City and Long Island based on the combination of energy market margins and capacity market payments, the economics of new generation investment have depended critically on the substantial capacity payments in the New York market, particularly for generation located in New York City and on Long Island. The New York independent market monitor has consistently found that energy market margins alone have been inadequate to sustain new generation investment.[9]

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7 PJM Market Monitoring Unit 2007, State of the Market Report, pp. 136-139, based on an annual levelized fixed cost of $143,000 per megawatt for a combined cycle and $90,600 for a 10,500 Btu heat rate combustion turbine. Reasonable people can differ on the likely level of some of the costs included in the calculations; costs would usually vary by location and there are elements of the hypothetical net margin calculation that might overstate or understate actual net margins, but the market monitor's figures adequately portray the historical relationship between margins in the spot energy market and the cost of new capacity.

8 PJM Market Monitoring Unit, 2007 State of the Market Report; compare Tables 3-7, 3-10, 3-11, 3-16, 3-19, 3-24 and Tables 3-8, 3-12, 3-13, 3-17, 3-20, and 3-26.

9 See, for example, David Patton, Pallas LeeVanSchaick, New York ISO 2006 State of the Market Report, July 2007 (hereinafter Patton and LeeVanSchaick, NYISO 2006), pp 10-18, located at http://www.nyiso.com/public/documents/studies_reports/market_advisor_reports.jsp/.

The market monitor's analysis based on day-ahead market and real-time commitment shows annual combined cycle energy and ancillary service market net revenues in the range of (U.S.) $100,000 to $150,000 per megawatt inside New York City on the 345 kv system, and in the range of $150,000 to $250,000 per megawatt in some load pockets inside New York City. In the Hudson Valley and Capital Zone, the estimated annual energy and ancillary service revenues of the benchmark combined cycle were in the range of only $50,000 to $135,000 per megawatt over the past five years, averaging about $110,000 in the Hudson Valley.[10] The annual net energy market revenues of the benchmark 30-minute combustion turbine were only $25,000 to $50,000 per megawatt on the 345 kv system in New York City, in the range of $50,000 to $110,000 per megawatt in load pockets inside New York City, and typically less than $50,000 per megawatt in the Hudson Valley and Capital Zone (see Table 2).[11]

Table 2
NYISO Energy and Ancillary Service Revenues
($ Thousands per Megawatt)

	Standardized Combined Cycle						
	2007	**2006**	**2005**	**2004**	**2003**	**2002**	**Average**
Long Island	235	275	250	140	155	170	204
Vernon Green[1]	200	190	245	165	180	160	190
Hudson Valley	145	135	120	60	80	na	108
Capital	125	90	105	60	90	60	88
		Standardized Combustion Turbine					
Long Island	80	115	80	25	45	80	71
Vernon Green[1]	85	85	110	65	77	70	82
Hudson Valley	45	45	35	5	25	na	31
Capital	35	30	30	5	20	35	26

Patton and LeeVanSchaick, NYISO 2007, Figures 11 and 12.
Patton and LeeVanSchaick, NYISO 2006, Figures 11 and 12.
Patton and LeeVanSchaick, NYISO 2005, Figure 11.
Patton and LeeVanSchaick, NYISO 2004, Figure 16.
All revenue data are based on graphs in the State of the Market Report and are approximate.
[1] New York City data are used for 2002.

A recent study by NERA of the capacity market payments required to sustain new investment in New York concluded that energy market margins fell short of those required to sustain the benchmark unit by almost (U.S.) $200,000 per megawatt year in New York city, by about $140,000 per megawatt year on Long Island, and by slightly more than $100,000 in upstate New York.[12] While reasonable people can disagree with various aspects of NERA's annual

10 Table 2.

11 Table 2.

12 NERA, "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," August 3, 2007, pp. 9-11, located at www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2007-08-07/ICAPWG_Demand_Curve__Study_Report_80707_clean.pdf.

revenue requirement calculation, amortization period, cost of capital (including risk adjustments if any), construction costs, fixed O&M, working capital, variable O&M, it is clear that spot energy market revenues alone have been inadequate to sustain new generation investment in New York.[13]

New England

The ISO New England Annual Markets Reports have calculated upper bounds on the annual energy and ancillary service market revenues of a 7,000btu/kWh combined cycle ranging from $64,350 to $120,524 a year over the period 2003 through 2007 and averaging about $95,000/MW per year, as shown in Table 3. Similarly, the estimated energy and ancillary service market revenues of a 10,500btu/kWh combustion turbine ranged from $12,000/MW to $56,564 a year, averaging $44,251/megawatt per year.[14]

Table 3
ISO New England
Estimated Energy and Ancillary Service Net Margin
($ per Megawatt)

Average	2007	2006	2005	2004	2003
	Combined Cycle				
95,257.20	120524	103569	113843	64350	74000
	Combustion Turbine*				
41172.75	56564	47089	53102	52500	12000

Source: ISO New England, 2006 Annual Markets Report, June 6, 2008, p. 171, 2007 Annual Markets Report, p. 171. June 11, 2007, pp. 133-134. 2005 Annual Markets Report, June 1, 2006, pp. 130-132; 2004 Annual Markets Report, 2005, pp. 112-113. 2003 Annual Markets Report, 2004, pp. 58-60.

Like PJM, ISO-New England until recently had a non-locational capacity market that had a variety of features that typically caused it to clear at a near-zero price,[15] so the combination of energy and capacity market revenues was also insufficient to support new investment in capacity-short regions within New England.

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13 It needs to be kept in mind that low margins for particular types of generation at particular locations does not necessarily indicate an overall investment incentive problem, it may simply indicate that it does not make sense to locate that type of generation at that location. For example, the findings regarding 30-minute gas turbines outside New York City may simply reflect an economic reality that it does not make sense to locate 30-minute gas turbines outside of New York City and Long Island. However, the energy market margin of the benchmark 30-minute gas turbine has also been insufficient to support investment in such a unit either in New York City or Long Island.

14 ISO New England, 2006 Annual Markets Report, June 11, 2007, pp. 133-134. 2005 Annual Markets Report, June 1, 2006, pp. 130-132; 2004 Annual Markets Report, 2005, pp. 112-113. 2003 Annual Markets Report, 2004, pp. 58-60.

15 Scott Harvey, “Resource Adequacy Mechanisms: Spot Energy Markets and Their Alternatives,” June 28, 2006, Center for Research in Regulated Industries, 19th Annual Western Conference, Monterey California, pp. 48-51 (hereinafter Harvey, June 2006).

Midwest

In the Midwest, the Midwest ISO's independent market monitor estimated that during 2006 the annual energy market net revenues of a new combustion turbine would have ranged from \$20,000 to \$45,000 per megawatt across various regions within the MISO footprint. The corresponding annual net revenues of a new combined cycle unit would have ranged from \$50,000 to \$90,000 per megawatt.[16] The independent market monitor also concluded that if sustained over time these net revenues were insufficient to support investment in either new combustion turbines or combined cycles, even in the highest priced regions within the MISO, despite low capacity margins throughout the Midwest ISO.[17]

Texas

ERCOT's Independent Market Monitor estimated the net revenues of a new combined cycle or combustion turbine unit in each of the ERCOT zones over the period 2002 to 2006 and found that only in 2005 were the net revenues high enough to sustain investment in new capacity had they reflected the expected long-term energy margin, which they did not, as net revenues were much lower in all other years.[18] While net energy market revenues have been insufficient to support new investment in generation over this period, this outcome could be viewed as consistent with the overall level of adequate to surplus resource balance in ERCOT over this period.[19] Nevertheless, as discussed below the Public Utilities Commission of Texas has modified several elements of the ERCOT market design with the intent of providing improved generation investment incentives on a going-forward basis.

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[16] Potomac Economics, 2006 State of the Market Report, The Midwest ISO, July 2007, pp. 8-10, located at http://www.potomaceconomics.com/serv01.html. Because 2006 was the first full year of operation for the spot energy markets coordinated by the Midwest ISO, there is no comparable calculation available for prior years.

[17] Potomac Economics, 2006 State of the Market Report, The Midwest ISO, July 2007, p. 10.

[18] As discussed in the State of the Market Reports, these revenue estimates are approximations that do not account for all of the factors that actually affect net revenues; see Potomac Economics, 2007 State of the Market Report for the ERCOT Wholesale Electricity Markets, August 2008, pp. 40-42; 2006 State of the Market Report for the ERCOT Wholesale Electricity Markets, August 2007, pp. 45-47; 2004 State of the Market report for the ERCOT Wholesale Electricity Markets; July 2005, pp. 42-44.

[19] Potomac Economics, 2006, p. xiv.

As shown in Table 4, the estimated annual spot market margin of the benchmark combined cycle unit averaged around $70,000 per megawatt over these years, compared to the market monitors estimated annual net revenue requirement in the range of $95,000 to $125,000 per megawatt. Similarly, the estimated annual margin of the benchmark combustion turbine averaged less than $30,000 per megawatt, compared to an estimated annual net revenue requirement in the range of $60,000 to $85,000 per megawatt.[20]

Table 4
ERCOT Energy and Ancillary Service Revenues
($ Thousands per Megawatt)

	2002	2003	2004	2005	2006	2007	Average
	Combined Cycle						
Houston	19	51	51	140	90	95	74.3
North	15	52	51	135	88	90	71.8
South	18	45	48	125	80	90	67.7
		Combustion Turbine					
Houston	2	21	19	60	40	50	32
North	2	22	20	60	40	48	32
South	2	18	18	48	35	48	28.2

Potomac Economics, 2007 State of the Market Report for the ERCOT Wholesale Markets, August 2008, p. 41; 2006 State of the Market Report for the ERCOT Wholesale Electricity Markets, August 2007, pp. 45-47; 2004 State of the Market Report for the ERCOT Wholesale Electricity Markets; July 2005, pp. 42-44.

Ontario

The Ontario Market Surveillance Panel has carried out an analysis of net revenues based on the HEOP (hourly energy price) for a hypothetical generator in Ontario using very similar assumptions to those used by the PJM and New York Market Monitors and found that the average margin of a 10,500 heat rate gas turbine would have been (Can) $19,244 per megawatt over the period November 2002 through October 2007, well below the estimated costs of such a unit in the US, while the estimated margin of a 7000 heat rate combined cycle would have averaged (Can) $73,197, which is somewhat below the estimated cost of such a unit in the United States.[21]

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[20] Potomac Economics, 2006 State of the Market Report for the ERCOT Wholesale Electricity Markets, August 2007, p. 47. The Market Monitor's portrayal of net energy margins is graphical so the figures in Table 4 are approximate.

[21] Ontario Energy Board, Market Surveillance Panel, Monitoring Report on the IESO-Administered Electricity Markets, December 2007, pp. 62-63. http://www.oeb.gov.on.ca/OEB/Industry+Relations/Market+Surveillance+Panel

The Market Surveillance Panel also carried out a similar net revenues analysis based on the implicit nodal price in the IESO-constrained dispatch (i.e., the dispatch that determines physical dispatch instructions) for a location in Toronto and found that the margins in recent years would have considerably exceeded the margins required to support new investment in either a combined cycle (Can) ($202,400) or a combustion turbine ($119,300).[22] A similar pattern was found to exist in most regions of Ontario, other than the Northeast and Northwest, as shown in Table 5.

Table 5
Ontario Energy and Ancillary Service Revenues
($ per Megawatt)

	2002-3	2003-4	2004-5	2005-6	2006-7	Average
		HOEP Prices				
Combined Cycle	111467	52987	95181	45093	61257	73197
Combustion Turbine	31695	11128	28064	10181	15151	19244
		Nodal Prices				
Combined Cycle						
Toronto	278500	151400	248100	131400		202400
NE	209200	103800	147500	90100		137700
Bruce	261200	139100	220000	113100		183300
Northwest	129600	55800	25400	20100		57700
Combustion Turbine						
Toronto	164900	82000	153100	77200		119300
NE	122500	59800	82500	47800		78100
Bruce	152300	74500	132100	63100		105500
Northwest	76700	40400	18200	9500		36200
Source:						
Market Surveillance Panel, Monitoring Report on the IESO-Administered Electricity markets, December 2007, p. 63. Market Surveillance Panel, Monitoring Report on the IESO-Administered Electricity markets, July 2007, p.136.						

Conclusion

This review of energy margins in a number of competitive energy markets illustrates the common pattern in which net margins from the spot energy and ancillary service markets are insufficient to incent needed investment.[23] Moreover, in several of these regions, energy and ancillary service spot market margins have been insufficient even to cover the going forward (fixed operating) costs of existing generation. This problem of insufficient energy and ancillary

[22] Ontario Energy Board, Market Surveillance Panel, Monitoring Report on the IESO-Administered Electricity Markets, July 2007, pp. 130-135. http://www.oeb.gov.on.ca/OEB/Industry+Relations/Market+Surveillance+Panel.

[23] This pattern of inadequate spot energy market margins to sustain generation investment does not exist in all markets. As discussed in Section III, Australia, Alberta and the United Kingdom rely on energy-only markets to incent generation investments.

services margins to sustain investment in new generation is often referred to as the "missing money" problem.[24]

B. Causes of the Missing Money Problem

The insufficiency of energy revenues from the standpoint of incenting generation investment typically arises from a combination of several features of retail and wholesale energy markets.[25]

- Low values set for reserve shortages in real-time or hard reserve requirements combined with low bid caps and/or cost-based offer price mitigation.
- Real-time prices are not set by consumer's willingness to pay.
- Unpriced second contingency unit commitment requirements.
- Capacity market requirements and payments.
- Single price and zonal energy markets.

The primary factor contributing to the inadequacy of energy market margins to support investment is that with offer caps and reserve shortage costs set at relatively low levels in most competitive generation markets, real-time prices can not rise high enough, even during reserve shortages, to induce much demand curtailment or to contribute much to generator net margins. This is currently the case in most U.S. spot electricity markets, which have offer caps set at (U.S.) $1,000/MWh and in Ontario, which has bid caps set at $2,000,[26] well below the level that would be required for suppliers to recover the cost of new capacity in energy margins during hours of reserve shortages.[27] This problem is particularly acute in load pockets in which there may be very little competition when transmission constraints are binding and generator offers are therefore typically capped at levels well below the overall $1,000/MWh offer caps. Capping offers of resources located in load pockets at variable cost in this manner precludes the exercise of locational market power by the resources located within the load pockets, but offer capping in this manner also guarantees that the offer capped units will not recover the spot energy market

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24 See, for example, Abram W. Klein, Edison Mission, "Too Little Money," Harvard Electricity Policy Group, May 21, 2003; William W. Hogan, "On an 'Energy Only' Electricity Market Design for Reserve Adequacy," September 23, 2005, located at http://www.whogan.com/; Paul Joskow, "Markets for Power in the United States: An Interim Assessment," *The Energy Journal*, Vol. 27, #1, 2006, pp. 15-16; and the FERC RPM Order, 117 FERC ¶61,331, December 22, 2006 at 3.

25 See, for example, Paul Joskow and Jean Tirole, "Reliability and Competitive Electricity Markets," *Rand Journal of Economics*, Spring 2007, pp. 60-84.

26 ERCOT, discussed below, currently has a slightly higher bid cap (U.S. $2,250/MWh) and this bid cap will rise to $3,000/MWh with implementation of LMP pricing.

27 With a $2,000/MWh price and fuel and short-run O&M costs of $100/MWh (probably low in today's markets) the hours of reserve shortage would need to *average* around 40-50 hours a year to support investment in new combustion turbine capacity, even outside high-cost load pockets.

margins they need to remain in operation and ensures that margins will also not reach the level required for new capacity to be constructed within the load pockets.[28]

The NYISO implemented reserve shortage pricing in 2005 that causes energy and reserve prices and margins to rise during shortage conditions (i.e., during reserve shortages) without regard to market participant offer prices. However the shortage values are currently too low and the number of reserve shortage hours too few for energy market revenues alone to support the level of generation investment required to maintain the target level of reliability in New York.

An underlying element of the investment incentive problem is that because electricity cannot be stored, there must be enough capacity available to reliably meet load at all times, which means that the marginal generating capacity is rarely needed, either to generate energy or to provide reserves. While the industry meets peak load with generation resources that have relatively high energy costs and relatively low fixed costs, the fixed costs are still substantial and it is widely recognized that power and reserve prices in the general range of $10,000 per megawatt hour during shortage hours would be required to make investment in marginal generation resources profitable.[29]

This circumstance gives rise to a very difficult regulatory problem, because while 8 hours a year of prices at the $10,000 per megawatt hour level might allow firms to earn a competitive rate of return on their investment in marginal generating capacity, 80 hours a year of prices at this level due to the exercise of market power could double the cost of electricity to consumers over the year as a whole, yet the difference would arise from the successful exercise of market power on only a handful of days. This perceived potential for the exercise of market power has led to the imposition of the $1,000 per megawatt hour bid caps referenced above; however, these bid caps will generally make it impossible for firms lacking market power to earn a competitive return on marginal generation investments, while maintaining enough capacity in service to satisfy current reliability standards.[30]

A second factor contributing to inadequate spot energy market revenues to support generation investment is that is that while there has been a gradually increasing opportunity for

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28 PJM has struggled for several years with the problem of how to cap the offers of units located in load pockets in a manner that protects power consumers from the exercise of market power, while on the other hand, providing sufficient revenues to keep needed generation in operation, see for example the FERC Rehearing Order in Docket EL03-236-001, 110 FERC ¶ 61,053 January 25, 2005. For a general discussion both of PJM's bid caps and a review of the bid caps and market power mitigation mechanisms in other organized electricity markets, see James Reitzes, Johannes Pfeifenberger, Peter Fox-Penner, Gregory Basheda, Jose Garcia, Samuel Newell, and Adam Schumacher, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets," September 14, 2007. http://www.pjm.com/committees/task-forces/tpstf/downloads/20071018-item-3b-brattle-mitigation.pdf

29 See, for example, Benjamin Hobbs, Affidavit, August 31, 2005, in EL05-148-000.

30 The system operator could, in principle, increase its target level of operating reserves so that there would be a larger number of reserve shortage hours during a normal year, allowing a correspondingly lower bid cap or reserve shortage value to provide a competitive return on new investment. This would produce inefficient short-run incentives, however, if the reserve shortage values exceeded the actual value of incremental reserves during these hours, causing consumers to incur the costs of committing capacity to provide the extra reserves and potentially causing inefficient demand reductions.

consumers in competitive power markets to respond to real-time power prices by reducing consumption, the price of power is generally not determined by the price at which consumers would prefer to reduce consumption. This outcome is partly circular; since energy prices are capped at low levels there is little price-responsive real-time demand curtailment at typical price levels. Given the lack of price-responsive demand, enough generating capacity is procured to ensure reliability with little need for real-time demand curtailment. Because energy prices are low, the required generating capacity is not economic based on energy market revenues alone. The underlying problem is not that the lack of demand response causes energy prices to be high, rather that energy prices are not allowed to rise to sufficiently high levels that consumer's response to high prices can define capacity needs.[31]

A third factor contributing to the insufficiency of energy market revenues has been the failure of some competitive markets to price operating reserves. This was a particular problem in New England where second contingency reserve requirements (or as some would term it, one plus one contingency requirements) were accounted for in the day-ahead unit commitment but were not priced in the day-ahead (or real-time) market. Thus, enough generation was committed day-ahead to ensure that a single contingency would not result in a situation in which load shedding within the pocket load would be necessary to maintain reliability (i.e., to restore the ability to meet the next contingency), but no value was attached in the pricing system to the capacity committed for this purpose. As a result, units within the affected load pocket would be committed uneconomically at minimum load and energy and ancillary service prices would be no higher within the load pocket than outside, as no transmission constraints would be binding in a (first) contingency constrained dispatch. The units that were uneconomically committed would be made whole for the costs they incurred in operating at minimum load, but this pricing would not allow them to recover their going-forward costs. With no binding transmission constraints in the energy market and no compensation to capacity providing these reserves, it was predictable that energy margins would be insufficient to incent the construction or continued operation of enough capacity within these second contingency load pockets to maintain historic reliability levels.[32]

A fourth factor contributing to the typical insufficiency of energy market revenues from a generation investment perspective is that other non-energy market mechanisms are used to procure enough capacity so that reserve shortages are relatively rare, implying relatively limited energy market revenues unless prices are quite high during these few hours. In the NYISO, for example, the New York State Reliability Council sets the targets for the NYISO capacity market and this capacity is procured at fairly high cost, at least in New York City and Long Island. With this capacity procured in the capacity market, the number of reserve shortage hours in the energy market is relatively low. Similarly, until recently, PJM and ISO-New England did not have

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[31] It is also important to understand that the presence of substantial demand response does not lower the prices needed to sustain the capacity needed for reliability but will simply reduce the amount of capacity that will be needed to meet load and avoids the construction of capacity that costs more than its value to consumers.

[32] This problem was addressed, at least in part, with the 2006 implementation of locational reserve markets, including second contingency reserve requirements, see ISO New England filing letter in Docket ER06-613-000, February 6, 2006; approved by the FERC in 115 FERC ¶ 61,175 May 12, 2006. It is perhaps noteworthy that following the implementation of the locational reserve market, the initial forward capacity market cleared at the preset minimum price with a uniform price across New England.

functional capacity markets but supported needed generation through a variety of RMR contracts, which had the same effect as capacity market payments of depressing energy market margins for resources not receiving RMR contracts.

Several of the issues described above affect investment incentives in the Ontario energy market. While Ontario has about 700 MW of dispatchable load which can set price, it seldom does. As in most jurisdictions, the energy price in Ontario rarely rises to the point at which customers are willing to reduce consumption. In addition, there is a lack of demand side representation as Ontario does not have load serving entities and while rules allow for load aggregation, it is not widely used. Some programs have been established to facilitate load response, however, these are outside the market and do not influence price.

Bid caps in Ontario are set at $2,000; however, energy prices rarely reach the point where the cap has been binding. Reliability programs have in recent years ensured the availability of sufficient capacity so shortage pricing is seldom relevant. The day-ahead commitment program, coupled with a day at hand commitment process, hour-ahead import guarantees and OPA supply contracts have maintained reliability without the need for extensive shortage pricing.

Another factor affecting investment incentives that is relevant to Ontario energy markets is the lack of locational energy pricing. Ontario real-time prices are artificially low in the region in which investment in new generation is needed because real-time prices are set in a hypothetical dispatch that does not take account of transmission and a variety of other constraints on generator output. Some of these other elements of the Ontario unconstrained pricing system tend to discourage investment in the right type of capacity (i.e., low returns to quick ramping capacity.) Calculations by the Market Surveillance Panel of the Ontario Energy Board indicate that although generator margins calculated from the hypothetical HOEP (hourly unconstrained) price are far below the cost of new capacity within the regions in which capacity is needed, margins calculated based on the implicit LMP price would be well above the cost of new capacity (see Table 5 above), suggesting that the lack of locational energy pricing in Ontario may be deterring economic generation investments and raising consumer costs. Similar issues with incenting generation investments within constrained regions have arisen in the single price or zonal markets in Alberta, the United Kingdom and California, which calculate energy prices in a hypothetical unconstrained dispatch.

III. MECHANISMS FOR INCENTING GENERATION INVESTMENT

Given the frequent inadequacy of energy market revenues in competitive power markets from the standpoint of incenting investment, regulators and system operators in the affected regions have had to develop other mechanisms to ensure that the aggregate level of capacity needed to maintain reliability is built and remains in operation. The approaches taken in the various regions to providing incentives for generation investment by supplementing energy market revenues fall into four general categories.

A. RMR Contracts

Regions such as Alberta, the United Kingdom, Ontario and California that rely on single price or zonal energy markets make additional payments to generation located within load pockets that must be dispatched out of merit to maintain reliability because the energy market revenues would be insufficient to cover even incremental energy costs, let alone provide a return of and on investment sufficient to induce the construction of new generation. These contracts have different names and varying terms in each region but the essence is that the generation owner receives payments in excess of the clearing price in the energy market in exchange for remaining in operation and agreeing to be dispatched at an agreed-upon cost (or cost formula) when needed.

Similar issues arose in PJM and New England under their locational pricing systems for energy because although the energy revenues were sufficient to cover the incremental energy costs of generation located within the load pockets, the application of market power mitigation to the energy offer prices of these resources meant that they were unable to recover their going forward costs in their energy market revenues. The initial approach taken in PJM and New England to the inadequacy of energy market revenues to support the continued operation of generation located in load pockets and subjected to offer price mitigation (combined in PJM and New England with a lack of well functioning capacity markets) was to enter into what were termed reliability must-run (RMR) contracts with generation resources whose operation was required to maintain reliability but who would otherwise cease operations due to inadequate energy market revenues to cover their going-forward costs. While this approach is sometimes perceived as having an advantage for consumers of only making additional payments to high-cost resources that would otherwise shut down, rather than making payments to all similarly situated suppliers, this approach has features that tend to raise consumer costs.

First, the typical RMR contract mechanism does not provide a process for lower cost alternatives to displace high cost incumbent suppliers. Energy market prices could be inadequate either to cover the going-forward costs of the incumbent, to incent demand response, or to incent investment in new generation, yet the sum of the energy market and RMR payments to the incumbent supplier could be far more than required to induce demand response or new generation investment. As a result there is a potential under an RMR contract process for the RMR process to meet load at a much higher than necessary cost to consumers.

Second, the implicit assumption that an RMR process will inevitably result in contracts that just cover going-forward costs for the efficient operation of existing generation may be unwarranted. RMR contracts tend to be the result of negotiation or regulatory litigation. Some of the resulting contracts appear to have breathtakingly high costs. For example, the annual revenue requirement of the 157MW Pittsfield plant in New England, excluding variable O&M and fuel, was $36, 529,015, or somewhat more than $232,000 per megawatt year.[33] The test year revenue calculation was even worse, portraying annual margins of $4.315 million against annual fixed costs of $44.08 million, for a net cost of over $252,000 per megawatt year.[34]

Third, RMR contracts may start by covering a single problem generator and the process may appear manageable to regulators in the case of the single generator, but if RMR contracts are relied upon to maintain resource adequacy, their scope is very likely to expand down to cover many generators, imposing a large resource burden on the relevant regulators to apply the RMR

[33] See Pittsfield November 30, 2005 filing in Docket ER06-262-000, Attachment 2, Exhibit MRK-2 schedule 1.

[34] Pittsfield, November 30, 2005 filing, filing letter, p. 9.

process. Overall in New England during 2006 there were 5843 megawatts covered by RMR agreements, at a total net annual cost of $482 million, for an average annual net cost of about $82,000 per megawatt.[35] Similarly, PJM was on the verge of being overwhelmed by a tidal wave of RMR contracts to keep generation in eastern PJM in operation prior to the implementation of its RPM capacity market design.[36]

The Lennox unit is an example of a unit in Ontario that is kept in operation by RMR-type payments. In 2005, Ontario Power Generation applied to deactivate 2,140 MW of installed capacity at Lennox because it was not able to recover its going forward costs. The IESO denied Ontario Power Generation's request to deactivate Lennox. A reliability must-run contract was signed with the IESO and reviewed in a public process with the Ontario Energy Board which has oversight over the Ontario energy market. The cost of the contract is recovered through an uplift charge paid on all Ontario power consumption and the recovery of the uplift payments were estimated to add $0.39/MWh to the average cost of every megawatt of power consumed in Ontario.[37]

In practice, RMR contracts have generally not been used to provide incentives for new investment, but only to keep existing facilities in operation. As noted above, this is one of the limitations of this approach, it does not provide a mechanism for competition between new and existing capacity. Moreover, a system of RMR contracts for existing high-cost generation does not address the problem of incenting the construction of new capacity needed to meet growth in demand. In part for these reasons, in the United States, the FERC has fairly actively pushed PJM and New England to find another way to ensure resource adequacy.[38]

B. Capacity Requirements

The implementation of a capacity requirement and associated capacity market is the approach that has been taken to address the "missing money" problem in PJM, ISO-New England and NY ISO. The essence of a capacity market is that a requirement to contract for generating capacity is imposed on all LSEs in the region. Each LSE must contract for sufficient resources to cover the capacity requirement for its customers. The aggregate capacity requirement for the market is set by the appropriate regulatory authority to ensure that sufficient capacity is available to maintain the target level of reliability. Locational and other criteria must also be established to define the

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35 ISO New England, 2006 Annual Markets Report, June 11, 2007, pp. 99-100.

36 See PJM filing letter, August 31, 2005, Docket EL05-148-000, pp. 5-6, 40-45; Affidavit of Steven Herling, August 30, 2005 in Docket EL05-148-000, pp. 7-10 and attachment 2; and the FERC RPM Order 117, ¶61,331 at 11,12. See also Dockets EL03-116-000 and EL02-236-000 generally, and particularly Reliant's April 2, 2003 filing in Docket EL03-116-000 and FERC's May 6, 2004 Order in Docket EL03-236-000.

37 See Ontario Energy Board ruling EB 2005-0490, March 13, 2006, at http://www.oeb.gov.on.ca/documents/cases/EB-2005-0490/decision_130306.pdf and EB 2006-0205, January 22, 2007, at http://www.oeb.gov.on.ca/OEB/Hearings%20and%20Decisions/Decisions%20and%20Reports/2007%20Decisions%20and%20Reports

38 See, for example, 103 FERC ¶61,082, April 25, 2003 at 29, 31.

resources that will satisfy the regulatory capacity requirement.[39] In theory, in a competitive generation market, the requirement for LSEs to contract for capacity will cause capacity payments to rise to the level required to make up the "missing money" for the amount of capacity required to meet the capacity requirement and to keep the marginal existing resource in operation or induce the entry of new, lower cost capacity.[40]

In practice, however, a number of problems have emerged in using capacity requirements to provide the missing money and ensure the viability of capacity needed to maintain reliability. First, as observed above, the capacity market designs initially implemented in New England and PJM were ineffective in making up the "missing money" and were ineffective in either incenting the construction of new generating capacity or keeping existing generating facilities in operation where they were needed to maintain the target level of reliability. A key limitation of both of these initial capacity market designs was that they were non-locational, i.e., all capacity received the same clearing price in the capacity market, and this price was too low to sustain generation in some load pockets, requiring that the ISOs resort to RMR contracts as discussed above to keep in operation generation needed to maintain reliability within these load pockets.

In response to this problem PJM implemented a locational capacity market (called the RPM design) in which capacity is procured on a three-year forward basis with the auctions, covering the 2007-2008 capacity year the 2008-2009 capacity year, and the 2009-2010 capacity year having already been conducted.[41] In the most recent PJM forward capacity auction, capacity prices have ranged from $102,000 per megawatt year in western PJM to $237,300 per megawatt year in the load pockets in eastern PJM.

ISO-New England has also recently implemented a locational capacity market in which capacity will ultimately be purchased on a forward basis.[42] In the initial auction locational capacity market prices cleared throughout New England at the pre-determined floor price of $4,500/megawatt month, or $54,000 per megawatt year.[43]

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39 One can also envision a system which required LSEs to enter into contracts for enough energy to meet their load but such a system would not be effective in incenting generation investment unless combined with a requirement that the energy contract be backed with physical capacity as in a capacity market or if the energy prices were high enough to incent generation investment, even without the requirement.

40 For a more detailed conceptual explanation of the operation of competitive capacity markets, see Harvey, June 2006, pp. 4-7.

41 See PJM's September 29, 2006 filing in Docket ER05-1410-002; Approved by FERC in 117 FERC ¶61,332 December 22, 2006; summarized in Scott Harvey, "PJM RPM Capacity Model," August 10, 2007 posted at http://www.caiso.com/1c39/1c397da271b20.pdf

42 See ISO New England February 15, 2007 filing in ER07-546-000, approved by FERC in 119 FERC ¶61,045 April 16, 2007 and 120 FERC ¶61,087 July 25, 2007. See also, Scott Harvey, "ISO-NE FCM Capacity Market Design," October 9, 2007 (hereinafter Harvey, October 2007) posted at http://www.caiso.com/1c72/1c729b3c4f410.pdf

43 See ISO New England, Forward Capacity Auction Results Filing, March 3, 2008 Docket ER08- , filing letter, p.4. Since in the New England design the monthly capacity market revenues are deducted from the forward reserve payment, suppliers that have fully contracted their capacity in the forward reserve market would indifferent to the level of capacity market prices, perhaps contributing to the lack of locational constraints in the forward capacity market.

New York's capacity market has had locational requirements since its implementation, with high capacity market prices within New York City and Long Island. In New York, for example the annual capacity market revenues of a resource located in New York city has been slightly over $100,000 per megawatt over the period 2004-2006, but only in the range of $10,000-$20,000 per megawatt in the rest of the state (Hudson Valley, Capital Zone, etc.).[44]

While locational requirements have now been included in PJM's RPM capacity market design and in New England's FCM design, it has not been seen how well these designs will perform over time with changing patterns of generation and transmission investment. New York has had a locational capacity market with three regions since 1999, but there have been concerns in recent years that absent changes that raise energy and ancillary service margins, additional capacity market regions will be needed to maintain appropriate investment incentives in all regions across the state.[45]

A second problem with these initial market designs was a tendency for capacity prices to either be near zero or at the level set by the deficiency penalty because the time frame of the capacity markets (monthly or daily) was much shorter than the time frame in which capacity could enter or exit the market. This tendency was exacerbated in PJM where the capacity obligation was originally defined on a daily basis (to accommodate load shifting under retail competition),[46] and capacity could delist on the days the capacity was more valuable outside PJM than the daily penalty price. As a result, the supply of capacity in these early capacity markets was extremely price inelastic, absent the exercise of market power. The clearing prices in these short-term auctions provided a very poor price signal for new generation investment because if capacity was built as needed and offered at incremental cost, the market-clearing capacity price was likely to be close to zero. Conversely, because the supply of capacity is very inelastic in the short-run timeframe of daily or monthly auctions, there was a potential for the exercise of market power through economic or physical withholding. This feature of capacity markets is not necessarily a limitation, as LSEs willing to enter into long-term contracts would be able to contract forward for capacity with new entrants on a long-term basis in a timeframe in which supply is elastic because new capacity can be built. This feature of capacity markets is a problem, however, in regions like New York, New England and PJM where due to retail access programs, most LSEs do not have a long-term obligation to serve and therefore have typically been unwilling to enter into long-term capacity contracts.

This aspect of the initial capacity market designs was addressed to a degree in New York with the implementation of a capacity market demand curve. The implementation of the capacity demand curve made the demand for capacity slightly price elastic, purchasing more capacity when the clearing price in the capacity auction was low relative to the estimated equilibrium price and less when the clearing price was high relative to the estimated equilibrium

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44 Annual capacity market revenues have been in the range of $75,000 to $100,000 per megawatt on Long Island.

45 For example, David Patton, Pallas LeeVanSchaick, "New York ISO 2006 State of the Market Report, July 2007," p. 110
http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2006_state_of_market_report.pdf

46 A more complete discussion of these problems is found in Harvey, June 2006 pp. 43-70. See also Initial Order on Reliability Pricing Model, 115 FERC ¶61,079 at 23-24, 35-36.

price.[47] The PJM RPM market also includes such a demand curve for capacity.[48] While the implementation of these demand curves has introduced stability into capacity market prices, the supply curve for capacity is still largely fixed within the time frame of the short-term auctions.[49]

Another innovation in the PJM RPM market and the ISO New England FCM capacity market designs to address this limitation of the early capacity market designs was to procure capacity on a three-year forward basis, i.e., in a timeframe in which point capacity investments are not yet sunk.[50] New York market participants are also considering the implementation of a forward auction in its capacity market.[51] The underlying problem, however, is not the design of the capacity markets in these regions but the design of the underlying retail market in which no entity has a long-term obligation to serve load in any retail access states. There is nothing to prevent LSEs in retail access states from entering into long-term capacity contracts on their own; the underlying problem arises from LSEs in retail access states that lack any long-term obligation to serve load and consumers in such states that conversely lack any obligation to pay for long-term obligations entered into to serve their load. Forward capacity market purchases effectively put the ISO in the position of entering into forward capacity contracts on behalf of retail access load and collecting the costs required to cover these contracts.[52]

A significant element of the NYISO capacity demand curve and PJM's RPM demand curve is the periodic calculation of an estimated equilibrium capacity price, based on the estimated cost of new entry.[53] There are many elements of these calculations upon which

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47 Patton and LeeVanSchaick, NYISO 2006, p. 106.

48 See PJM, September 29, 2006 Filing Letter, Docket ER 05-1410-000, pp. 7-11.

49 A side benefit of the capacity demand curve is that capacity payments are not zero for any capacity in excess of the forecasted capacity requirement. A potentially significant disadvantage of a capacity requirement system is that if spot energy prices are capped and generation investment driven by capacity market payments, there would be little, if any, return to capacity in excess of the target, even if it turned out after the fact to be badly needed. The implementation of a downward sloping demand curve in the capacity market provides some ability for the financing of contrarian investments, but it provides payments for the additional capacity without regard to whether the additional capacity proves in practice to be needed or surplus.

50 See PJM, September 29, 2006 Filing Letter, Docket ER 05-1410-000, pp. 11-13.

51 NERA, "Outline for A Forward Capacity Market for NYISO," August 7, 2007. http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2007-08-07/ICAPWG_Forward_Cap_MKT_Preliminary_Concept_080707_final.pdf. NYISO Proposed Forward Capacity Market Design – Details Part 1, Installed Capacity Working Group, October 3, 2008; NYISO Proposed Forward Capacity Market Design – Details Part 3, Installed Capacity Working Group, November 20, 2008.

52 Entities with long-term load serving obligations, such as traditional distribution companies in non-retail access states and state power authorities and municipal utilities in retail access states can enter into longer term energy or capacity contracts with durations much longer than those in the forward capacity auctions coordinated by the ISOs. Such entities would also have the ability to enter into long-term energy contracts in an energy-only market design.

53 In ISO New England's FCM capacity market design, the initial estimated equilibrium cost of new capacity (CONE) is specified in the tariff and then adjusts over time based on the results of the forward capacity auctions. February 15, 2007 Filing Letter, p. 118. Market Rule 1, Section III.13.2.4.

reasonable people can disagree, and there are already a number of regulatory proceedings concerning disputes as to the appropriate level of these prices.[54]

A third limitation of the initial capacity market designs were the relatively limited incentives for real-time availability provided by these capacity market designs. If capacity markets are combined with low bid caps and low reserve shortage values that keep spot energy prices relatively low even during shortage conditions, then suppliers will not have the socially efficient level of incentives to incur costs to keep their generation on-line during stressed system conditions. While under the initial market capacity designs, generators that were not available during shortage conditions as a result of forced outages lost a prorata share of their capacity payment, this penalty did not reflect the full social cost of these outages when they occurred during shortage conditions. The low level of penalties for generation that is not available during reserve shortages has generally not given rise to substantial incentive problems with regard to forced outages arising from mechanical failures, which are random and uncorrelated across units.[55] These performance incentives have become more problematic in the case of generators that were not available in real-time during periods in which gas prices were very high, because they chose not to buy gas, or had no dual fuel capability, or had no fuel in storage, because these failures were not random and uncorrelated across units as are normal forced outages, but were highly correlated across gas fired units which all faced the same high gas prices.[56] ISO-New England has attempted to provide better incentives for generation availability under its FCM design by attempting to better relate capacity payments to availability during shortage conditions, but it has not yet been seen how well these provisions work in practice, how they will affect the viability of energy-limited units, or how the provisions will affect the price of capacity.[57]

Similar performance issues have arisen for demand response resources within regions relying on capacity payments to maintain resource adequacy. Since spot energy prices in these markets are too low to provide an incentive for the efficient level of demand response, demand response resources in these regions receive additional payments for reducing consumption relative to a baseline when needed to maintain reliability. These payments for reductions in consumption relative to hypothetical baseloads have apparently led to excessive consumer costs and recent changes in the demand response program design in New England,[58] and similar issues have arisen in PJM and New York.[59]

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[54] See, for example, the RPM Buyer's Protest in Docket ER08-516-000, and the many disputed issues in the NYISO's demand curve update for the 2008/2009, 2009/2010 and 2010/2011 capacity years, 122 FERC ¶61,064 January 29, 2008.

[55] Capped spot prices also reduce the incentive of the generation operator to incur extraordinary costs to return generation to service during extreme operating conditions.

[56] These incentive issues are discussed at length in Harvey, June 2006, pp. 71-110.

[57] See Harvey, October 2007, pp. 11-13 for a discussion of some of the potential issues.

[58] See ISO-NE February 5, 2008 filing in docket ER08-538-000 regarding its Day-Ahead Load Response Program and the discussion in the April 4, 2008 FERC order in this docket.

[59] See PJM Market Monitoring Unit, 2007 State of the Market Report, pp. 107-108. PJM Filing Letter, Docket ER08-824-000, April 14, 2008.

Capacity market programs therefore have to deal with the twin problems of avoiding capacity payments to demand response providers for hypothetical reductions of consumption that never would have occurred, while also avoiding paying high prices for generation resources that meet load that would rather reduce consumption than pay such a high price. Moreover, the design of capacity markets in which demand response resources receive a fixed payment for an unlimited obligation to reduce consumption when activated, means that tightening of reserve margins reduces the incentive to provide demand response.[60]

Another intractable problem associated with capacity markets that is not completely addressed either by the introduction of demand curves or forward capacity procurement is the potential for the exercise of market power by incumbent generators to raise capacity market prices by withholding capacity or strategic behavior by large net buyers to depress capacity market prices paid to inframarginal generation. These kinds of concerns recently motivated a number of changes in the design of the New York capacity market,[61] and both the PJM RPM market and the New England forward capacity market contain a multitude of provisions intended to address the potential for the exercise of market power by buyers and sellers.[62] The identification of market power is particularly complex in capacity markets because they are forward looking, clearing in a competitive market based on expected costs, and expected margins, rather than markets that clear based on short-run incremental costs.

Finally, many of these capacity markets have a fundamental circularity because the amount of capacity needed to maintain reliability depends on the characteristics of the capacity used to meet the requirement, so it is not really possible to define the requirement independently of the characteristics of the capacity procured to meet the capacity requirement. This does not matter much in short-term capacity procurement processes because the supply of resources is pretty much known when the capacity target is set, but it will become more of an issue in forward procurement auctions.

Some of these potential limitations of the initial capacity market designs have been addressed by a variety of capacity market design modifications in PJM, New England and New York, but the long run effectiveness of these changes is presently unclear and likely will not be known for several years.

C. Spot Market Scarcity Pricing

An alternative approach to incenting investment in generation, as well as incenting demand response, would be to avoid the situation in which spot market revenues are insufficient to support the efficient level of generation investment by allowing energy market prices to rise to appropriately high levels during shortage conditions, with the prospect of high margins during

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[60] Demand response resources are likely to be interrupted more often as the reserve margin falls, while the reduction in the required capacity is likely at least initially to reduce the capacity payment.

[61] See Docket EL07-39-000.

[62] See ISO-NE February 15, 2007 Filing Letter, Docket ER07-546-000, pp. 35-43, 69-79, 96-97, 106-108, 129-131; PJM Filing Letter, September 29, 2006, Docket ER05-1410-000, pp. 29-36; and Supplement Affidavit of Joseph Bowring, pp. 4-6.

capacity shortages incenting the construction of new generation, and incenting consumers that cannot reduce consumption in response to high real-time prices to enter into forward contracts to hedge their cost of power. High spot prices during reserve shortage conditions would also incent consumers able to reduce consumption to do so and incent generation owners to incur extraordinary costs to keep their generation on-line during these shortage conditions. This approach is sometimes referred to as an "energy only" market, has been implemented in Australia, Alberta and the United Kingdom, and is the approach that ERCOT and the MISO are in the process of implementing, or considering, using different methods.

The Australian market currently sets the spot market price cap at a relatively high level, $10,000 Australian (corresponding to roughly $8,000 in Canadian dollars or $6,500 in U.S. dollars). There is also no mitigation of supplier offer prices nor prohibition on the withholding of capacity from the spot market; however, the bid cap is subject to being temporarily lowered once the calculated annual revenues for a hypothetical unit exceed a specified level.[63] Such a rule reduces the potential for the exercise of market power arising from temporary conditions to produce sudden extremely large wealth transfers but it would not prevent an entity possessing structural market power from exercising it year after year. We have not undertaken any independent review of conduct in the Australian spot market for this paper. Some who have reviewed the market have concluded that there is a potential for the exercise of market power in the spot market and that price spikes are driven by physical or economic withholding; however, that finding may reflect the models used to test for withholding rather than actual conduct.[64]

One analysis suggests that Australian prices have generally been at a level sufficient to support new investment, except possibly in South Australia.[65] Another analysis indicates that while investment in peaking plants would clearly appear to be profitable in New South Wales and Queensland based on the average annual margins over recent years, the picture for new investment in South Australia and Victoria is more ambiguous.[66] A substantial proportion of the investment in new generation in Australia has apparently been by state governments and issues have been raised as to whether these investments have yielded market returns.[67] Overall, whether due to the exercise of market power or market forces, spot prices appear to have been at the level required to support new investment, at least in some regions of Australia.

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63 See NEMMCO, "Operation of the Administered Price Provisions in the National Electricity Market," located at http://www.nemmco.com.au/dispatchandpricing/ISO-0014.pdf

64 See Bardak Ventures Pty Ltd, "The Effect of Industry Structure on Generation Competition and End-User Prices in the National Electricity Market," May 2, 2005 (hereafter Bardak); Energy Reform Implementation Group, "Energy Reform the Way Forward for Australia," January 2007, pp. 66-71, located at http://www.bardak.com.au; James Reitzes, Johannes Pfeifenberger, Peter Fox-Penner, Gregory Basheda, Jose Garcia, Samuel Newell, and Adam Schumacher, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets," September 14, 2007.

65 Bardak, pp. 74-76.

66 Energy Reform Implementation Group, "Energy Reform the Way Forward for Australia," January 2007, pp. 62-64, located at http://www.erig.gov.au.

67 Energy Reform Implementation Group, "Energy Reform the Way Forward for Australia," January 2007, pp. 86-92; Bardak, pp. 25-26.

The United Kingdom has also relied on what are effectively energy-only margins to sustain generation investment located outside constrained regions.[68] Spot market revenues were adequate to incent substantial investments in new generating capacity in the United Kingdom during the 1990s, although this is often attributed in part to the exercise of market power by dominant incumbent generators who were able to raise prices well above the competitive level for a number of years.[69]

The United Kingdom has continued to rely on energy market revenues to incent investment (outside of load pockets) under the NETA market design. Although the NETA market design intentionally makes spot market performance and prices rather opaque and may deter entry by imposing artificial costs on firms lacking a generation portfolio,[70] spot market prices have apparently been high enough to incent contracting and generation investment.[71]

Alberta has also relied on an energy-only market to support generation investment, but with a $1,000/MWh price cap. The Market Surveillance administrator has concluded that prices have risen in recent years to the level required to incent new construction.[72] Historically, however, most new investment in Alberta generation has either been driven by co-generation opportunities in other industries or was built under Location Based Credit Standing Offer contracts (contracts for generation within constrained areas). Alberta policy makers identified a concern of whether the energy-only market provides sufficient price signals for generation investment but upon review determined that the province will continue to rely on the energy-only market supplemented by the centralized contracts for generation within constrained regions.[73]

The ERCOT approach to allowing appropriately high energy market margins during shortage conditions is explicitly modeled on the Australian energy-only market design, but with much lower bid caps.[74] To implement this design, the Public Utilities Commission of Texas raised the bid caps in the ERCOT market to $1,500/MWh on March 1, 2007, to $2,250/MWh on

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[68] Until implementation of NETA, the U.K. market included supplementary charges and payments that were sometimes referred to as capacity payments but they were more like energy payments than U.S.-type capacity payments.

[69] See, for example, David Newberry, "Electricity Liberalisation in Britain: The Quest for a Satisfactory Wholesale Market Design," *Energy Journal,* special issue, 2005 (hereafter, Newberry 2005).

[70] See Newberry 2005 and Alex Henney, "The Illusory Politics and Imaginary Economics of NETA," *Power UK*, March 2001.

[71] See Joint Energy Security of Supply Working Group, "JESS-Long-Term Security of Energy Supply," December 2006 Report, located at http://www.dti.go.uk/energy/jess. National Grid, "Summer Outlook Report 2008," located at http://www.nationalgrid.com/uk/electricity/sys/sumoutlook.

[72] Market Surveillance Administrator, "MSA Report, 2007 Year in Review, April 9, 2008 p. 7; MSA Report, 2006 year in Review, March 28, 2007, pp. 1-2, located at http://www.albertamsa.ca/8.html.

[73] See, for example, Alberta Department of Energy, Alberta's Electricity Policy Framework: Competitive-Reliable-Sustainable, June 6, 2005, pp. 35, located at http://www.energy.gov.ab.ca/electricity/687.asp.

[74] See Public Utility Commission of Texas, Project No. 31972, "Order Adopting Amendment to section 25.502, New section 25.504 and New section 25.505 as approved at the August 10, 2006, open meeting."

March 1, 2008[75] and will further increase the bid cap to \$3,000/MWh shortly after implementation of the ERCOT nodal market.[76] Entities controlling less than 5% of the installed generation capacity in ERCOT are deemed not to have ERCOT wide market power and therefore would be able to submit offers at the bid cap. As in Australia, in addition to these bid caps, there is an annual cap on the calculated net margin of a peaker (\$175,000) that will trigger reinstitution of a lower bid cap. In ERCOT, this lower bid cap will apparently remain in place for the remainder of that annual resource adequacy cycle. As part of the transition to an energy-only market based on spot market scarcity pricing, the Public Utility Commission of Texas rules that have triggered retroactive reductions in real-time prices were eliminated on October 1, 2006.[77]

The ERCOT scarcity pricing mechanism, like the Australian market, is apparently premised on market participants submitting what is referred to as hockey stick bids, offer prices that are very steeply upward sloping for the last few megawatts of capacity on a unit. While shortage pricing based on hockey-stick bids can produce high spot prices during shortage conditions, it has the potential limitations that spot prices may remain low even during shortage conditions or may rise to inappropriately high levels when there is no actual shortage of capacity as a result of the exercise of market power or misforecasting of market conditions by entities lacking market power.

The first outcome is possible because in a competitive market with reserve requirements, the decision of a few suppliers to offer the last megawatt of their capacity at the bid cap will often not cause prices to rise to the bid cap, even during a reserve shortage. Instead, the capacity with high offer prices would simply be scheduled to provide reserves. More complex strategies involving offering amounts of capacity at the bid cap that are related to the amount of reserves the resource can provide given its ramp rate would be more effective in raising prices. The more capacity is offered at the bid cap in this manner, however, the more likely is the second outcome in which high bid caps and high priced offers for more than the few megawatts of capacity may permit the exercise of market power, resulting in high power prices during conditions when there is no reserve shortage and high prices are unwarranted, or prevent efficient congestion management when congestion patterns differ from those expected when the hockey stick bids were submitted.[78]

An alternative approach to scarcity pricing in an energy-only market which is being implemented by the MISO as a part of its overall resource adequacy design, is to set appropriately high reserve shortage prices as part of the ancillary service market design so that

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75 Prices briefly rose to \$2,250/MWh on March 3, 2008 and were at this level or above for periods on a number of days starting on May 19, 2008.

76 See Public Utility Commission of Texas, Project No. 31972, "Order Adopting Amendment to section 25.502, New section 25.504 and New section 25.505 as approved at the August 10, 2006, open meeting," pp. 145-146; see also Potomac Economics, 2006, pp. 50-51.

77 See Public Utility Commission of Texas, Project No. 31972, "Order Adopting Amendment to section 25.502, New section 25.504 and New section 25.505 as approved at the August 10, 2006, open meeting." See also Potomac Economics, 2006, pp. 50-51.

78 These effects are illustrated in Scott Harvey, "Scarcity Pricing in New York and New England," prepared for California ISO, November 1, 2007 at http://www.caiso.com/1c87/1c87b1755f270.pdf

energy and ancillary service prices will rise to appropriate levels during reserve shortages without regard to market participant offer prices for energy.[79] In the initial MISO ancillary services market design, these shortage prices begin at $1,100/MWh and rise to $3,500/MWh if the MISO must implement involuntary load shedding.[80]

A potential limitation of energy-only market designs is that it is unclear if the commitment to allowing high prices during shortage conditions will be credible to consumers and investors and thus whether forward contracting and generation investment will be incented. It is easy to rely on energy-only pricing when there is excess generating capacity, the issue is whether it will be credible to consumers and investors that the high bid caps will be retained when excess capacity disappears and energy prices rise. A reliance on energy market revenues was espoused to incent generation investment in California, but when an energy and capacity shortage materialized in 2000 and there was little, if any, forward contracting by consumers, price caps were reduced and a variety of actions taken to suppress spot market prices. Consumers can get the worst of both worlds if spot prices rise to very high levels but because the commitment to allowing high spot prices to drive investment was not viewed as credible by either investors or load serving entities, there are no forward contracts for new capacity to hedge consumer costs and needed investment in generation, transmission or demand response does not occur.

In the United States, energy-only markets for resource adequacy have a credibility problem arising from FERC actions during and following the western power crisis. FERC recalculated power prices and required after the fact refunds based on calculations that used dramatically understated gas prices, ignored NOX allowance costs, and took no account of capacity shortages, even during hours of rolling blackouts.[81] The potential for such retroactive adjustments to prices during shortage conditions may have subsequently led to an unwillingness of merchant generators to make forward investments in generating capacity, or to contract forward for natural gas, natural gas storage or natural gas transmission.[82] Energy-only markets based on scarcity pricing have thereby been undermined by the political risk in the U.S. that if retail consumers are not hedged against price spikes, FERC will intervene to protect them from the consequences of their lack of forward contracting when spot power prices spike. With such an expectation, forward contract prices will not rise to the level required to justify investment in new generation resources and other mechanisms will be required to incent the construction and continued operation of generating capacity needed to maintain reliability.

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79 Midwest ISO, "An Energy Only Market for Resource Adequacy in the Midwest ISO Region," November 12, 2005, located at http://www.midwestmarket.org/publish/Document/3e2d0_106c60936d4_-74730a48324a?rev=1. New York currently applies reserve shortage pricing but the NYISO shortage values lower than those proposed by the MISO and are clearly inadequate to sustain generation investment without supplementation with capacity market revenues.

80 MISO Filing Letter, February 15, 2007, Docket ER07-550-000, pp. 23-26.

81 See, for example, 102 FERC ¶61,317, March 26, 2003 at 53-63, 98-122; 96 FERC ¶61,120, July 25, 2001.

82 See the discussion by Keyspan of generators in the U.S. Northeast reliance on non-firm gas transportation, Motion to Intervene and Comments of Keyspan Corp., FERC Docket ER01-3001-014, January 23, 2006, pp. 2-7.

Despite this post western power crisis political risk factor for energy-only markets, there is a history in the Midwest, going back to the summer of 1998, of very high spot power prices that were not revised or lowered after the fact by FERC to save unhedged LSEs from the consequences of their actions.[83] Since many regions of MISO are served by vertically integrated utilities (public or investor owned) with a long-run obligation to serve, the regulatory risk problem with an energy-only market is perhaps less severe in the MISO than elsewhere. If an individual utility in the Midwest failed to contract for sufficient generation to meet its customer load and as result had to pay very high spot prices for power, would FERC intervene to retroactively reduce spot prices as it did in California?

The current Ontario bid cap is $2,000/MWh. Ontario energy prices (the unconstrained price or HOEP) rarely reach $2,000/MWh and as of early December 2008 had only gone above $1,000/MWh for 54 five-minute intervals since market opening in May of 2002. Large increases in the bid cap (or higher shortage values) would be required for an energy-only market in Ontario based on the unconstrained price to provide appropriate incentives for generation investment. It is important to recognize, however, that these data apply to the hypothetical unconstrained price (the HOEP), rather than the actual constrained dispatch. As discussed above, calculations by the Market Surveillance Panel of the Ontario Energy Board suggest that generation investments would be profitable based on unconstrained prices at current Ontario bid cap levels.[84]

D. Centralized Long Term Forward Contracts

This is the approach that Ontario has taken to maintain resource adequacy since the summer of 2005. This approach entails a central entity entering into forward contracts for capacity and energy at prices sufficient to incent generation investment but in excess of the expected spot market value of the contracted energy.[85] The payment in excess of the spot market value of the energy provides the necessary incentive for new investment. It is important to understand that the crux of the difference between this approach to the missing money problem, and energy-only markets in which consumers are likely to enter into forward contracts to hedge themselves against price spikes in the spot market, is that under this approach a central authority enters into forward contracts for energy on behalf of consumers at contract prices that are not warranted by the level of expected future spot energy and ancillary service prices. Consumers are likely to

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83 See Staff Report to the FERC on the causes of wholesale electric pricing abnormalities in the Midwest during June 1998, September 22, 1998.

84 Ontario also suffers from a lack of LSEs able to enter into forward contracts for power, but simply establishing LSEs will not incent the LSEs to contract for power at prices sufficiently high to warrant the construction of new capacity. If expected spot prices are too low to support new investment, LSEs would simply buy power in the spot market to cover their load or contract with existing generators at prices reflecting expected future spot prices and some other mechanism would be needed to incent generation investment. ISO-New England has many LSEs and those LSEs enter into forward power contracts but because of the $1,000 per megawatt hour bid cap, the prices paid by the LSEs under the contracts have been insufficient to incent generation investment, causing ISO-New England to implement the forward capacity market.

85 The California DWR entered into contracts for power, many financing the construction of new generating facilities, during the western power crisis in early 2001. These contracts differed from the kind of centralized forward contracts discussed here in that they were, at the time they were signed, generally consistent with contemporaneous forward prices for financial power contracts.

enter into forward contracts (or distribution companies would enter into such contracts on behalf of their ratepayers) in the energy-only markets described in Section C, but under that approach expected future spot prices would be high enough to warrant entering into forward contracts at prices that would sustain new investment.

One limitation of the centralized contracts approach when employed in conjunction with spot energy prices that are capped at relatively low levels is that because the contract payments exceed the spot market value of the energy delivered it is not applicable for financial contracts and (as with a capacity market system) it is difficult to design completely efficient performance incentives for physical capacity procured by such contracts.[86]

A second potential limitation of this approach is that since this contracting approach must be centralized (because the contracts are uneconomic at expected spot market prices individual consumers would not rationally enter into them), there is a potential for a disconnect between the price at which power is purchased by the centralized purchasing entity and the price at which that amount of power will be demanded by consumers, resulting in the procurement of excess generating capacity and unnecessarily high power costs.[87] More generally, this approach centralizes the investment decision, making it difficult for contrarian views to drive generation investment. In an energy-only market, investors holding different expectations than LSEs or the RTO regarding the growth rate of demand, fuel prices, or other factors could make generation investments premised on these expectations, be proved correct or wrong by subsequent events, and be appropriately rewarded by their sales at spot market prices. If spot power prices are capped during shortage conditions, however, spot market revenues will be insufficient to incent investment by entities lacking a forward contract with the centralized agency.[88] Moreover, if this approach is adopted because spot energy prices are too low under this approach to incent the efficient level of generation investment, the prices will also be too low to incent the efficient level of demand response, requiring that demand response be incented through payments for

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86 The fundamental problem is that since the payments under the contract by definition exceed the value of the power at spot market prices, if the only performance penalty for a failure to deliver were a requirement to buy replacement power at the spot price, it would be profitable for a seller to enter into such a contract, build no new capacity, and pay the penalty for its failure to deliver. The underlying problem is that bid caps and other measures that limit the price paid by load under stressed system conditions also limit the revenue foregone by the generator that is not available during these stressed system conditions. The incentive problem can be addressed by adding additional penalties that withhold capacity payments when the plant is not available during specified conditions, but without spot prices that reveal the true value of spot power, it is difficult to design contract provisions that accurately reflect the social value of power and thus incent the supplier to incur extraordinary costs, but only when power is very valuable.

87 Centralized forward contracts also shift the risk of low spot power prices off suppliers to buyers (see Michael Wyman, "Power Failure: Addressing the Causes of Underinvestment, Inefficiency and Governance Problems in Ontario's Electricity Sector," C.D. Howe Institute Commentary, No. 26, May 2008, p. 8 [hereafter Wyman]), but this is true of any forward contract, whether centralized or negotiated by an LSE or end-use consumer. Moreover, it is important to keep in mind that such forward contracts conversely shelter the buyer from the effects of high spot power prices. Such forward power contracts are desirable to hedge consumers who cannot reduce their consumption from variations in spot power prices; the potential problem lies in centralized forward purchases on behalf of customers that can and would prefer to reduce their consumption when power prices rise, rather than paying a higher price when spot prices are low.

88 Along the same lines, see Wyman, p. 9.

reducing consumption (giving rise to the same kind of incentive and performance problems that have arisen in regions relying on capacity markets).

A third limitation of this approach is that because spot energy and ancillary service revenues remain below the level needed to sustain new investment, they are also too low to provide efficient incentives for existing capacity to remain in operation. As a result, such a system of above market forward contracts to finance the construction of new generating capacity will likely need to be accompanied by a system of RMR contracts to retain existing capacity in operation as it ages.

As observed above, there is currently one RMR contract in place in Ontario. In addition, the Ontario Power Authority (the central purchasing entity) signed contracts with several other existing generators, motivated by a variety of transition considerations.

IV. CONCLUSION

Competitive generation markets will not support the level of generation investment required to maintain historic levels of electric system reliability if bid caps and reserve shortage values are set at $2,000 per megawatt or below. Absent a decision to allow dramatically higher energy and reserve prices, and to provide a credible commitment that such high prices will be allowed to stand, some other supplementary mechanism is required to keep needed generation in operation and incent the construction of new generation. Capacity markets and centralized procurement processes can both be used for this purpose, but both share a number of common limitations arising from the low spot energy prices. If energy prices are capped at $2,000 per megawatt hour or less, there are no easy solutions to the generation investment problem.

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