ON AN “ENERGY ONLY” ELECTRICITY MARKET DESIGN FOR RESOURCE ADEQUACY

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September 23, 2005

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An “energy only” market design could avoid the need for increasingly prescriptive regulations targeted at ensuring resource adequacy. Transparent scarcity pricing would create better incentives for both operations and investment. An improved electricity market design would not eliminate all need for regulatory prescriptions. However, it would change the nature of the remaining problems and allow for market-based approaches that would not overturn the market.

Introduction

Electricity resource adequacy programs often target the “missing money” problem. The missing money problem arises when occasional market price increases are limited by administrative actions such as price caps. By preventing prices from reaching high levels during times of relative scarcity, these administrative actions reduce the payments that could be applied towards the fixed operating costs of existing generation plants and the investment costs of new plants. The resulting missing money reduces the incentives to maintain plant or build new generation facilities. In the presence of a significant missing-money problem, alternative means appear necessary to complement the market and provide the payments deemed necessary to support an appropriate level of resource adequacy.

In the United States experience, resource adequacy programs designed to compensate for the missing money create in turn a new set of problems in market design. The resource adequacy approaches become increasingly detailed and increasingly prescriptive to the point of severing the connections between major investment decisions and energy market incentives. Consideration of these new unintended consequences prompts interest in seeking ways to operate an electricity market without any money missing. This interest in turn requires further specification of an “energy-only” market design and consideration of alternative modifications of such designs that would address underlying policy concerns without recreating the missing money problems. The reference in quotes emphasizes that the intent is not to create a completely unregulated market. Rather the intent is to eliminate prominent imperfections in the market design and thereby change the nature of the regulatory prescriptions to allow for market-based approaches that would not overturn the market. The purpose of the present paper is to highlight the critical conceptual features of such an energy-only market.

There is an analogy here to other contexts with regulatory policies to influence markets to achieve public purposes without prescribing the technology or investments. For example, in the control of sulfur emissions from coal burning power plants there has always been a tension between command-and-control approaches that dictated technological solutions such as requiring scrubbers on all plants versus market-based approaches like cap-and-trade programs for sulfur emission allowances. The market-based approach targeted the problem (e.g., total emissions) rather than dictating the solution (e.g., scrubbers). The technology prescriptive approach for controlling sulfur emissions would have created high costs and unintended consequences. The alternative market-based approach with tradable emission allowances provided lower costs and better incentives. A similar task in electricity markets would be to establish better market designs and more compatible market-based interventions. In an energy-only market, the potential problems and objectives would be different and the same resource adequacy policy prescriptions might not be required.[1]

Missing Money

The missing-money analysis begins with the load cycle over the day and the seasons.[2] Changing levels of generation supply matched with changing load levels produce volatile costs. These costs include a mixture of the direct variable costs of marginal generators, energy values for storage limited hydro facilities, the marginal value of incremental demand, and so on. At the margin, we refer to the opportunity cost as the cost of meeting an increment of demand by decreasing other load or increasing generation. If contemporaneous spot prices reflect these opportunity costs, these prices would provide market participants with strong incentives during periods of scarcity. During most periods, market prices would be at a relatively low level defined by the variable operating costs of mid-range or base load generating plants. However, in some periods prices would rise above the variable operating costs of peaking units that were running at capacity and would reflect scarcity under constrained capacity with the incremental value of demand defining the system opportunity cost.

Spot prices could be summarized over the year by a price duration curve depicting the cumulative number of hours when prices exceed a given level. As shown in Figure 1, under perfect dispatch generation would operate according to its variable cost of production. The most expensive peak generation (e.g., $85/MWh variable cost) would operate for relatively few hours. The payments in area **A** above the operating cost of $85 would be the returns to cover the fixed costs of the peak plant, including the investment cost needed to compensate new entrants.

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[1] For a discussion of the objectives of resource adequacy programs, see James Bushnell, "Electric Resource Adequacy: Matching Policies and Goals," University of California Energy Institute, CSEM WP 146, August 2005.

[2] The characterization as "missing money" comes from Roy Shanker. For example, see Roy J. Shanker, "Comments on Standard Market Design: Resource Adequacy Requirement," Federal Energy Regulatory Commission, Docket RM01-12-000, January 10, 2003.

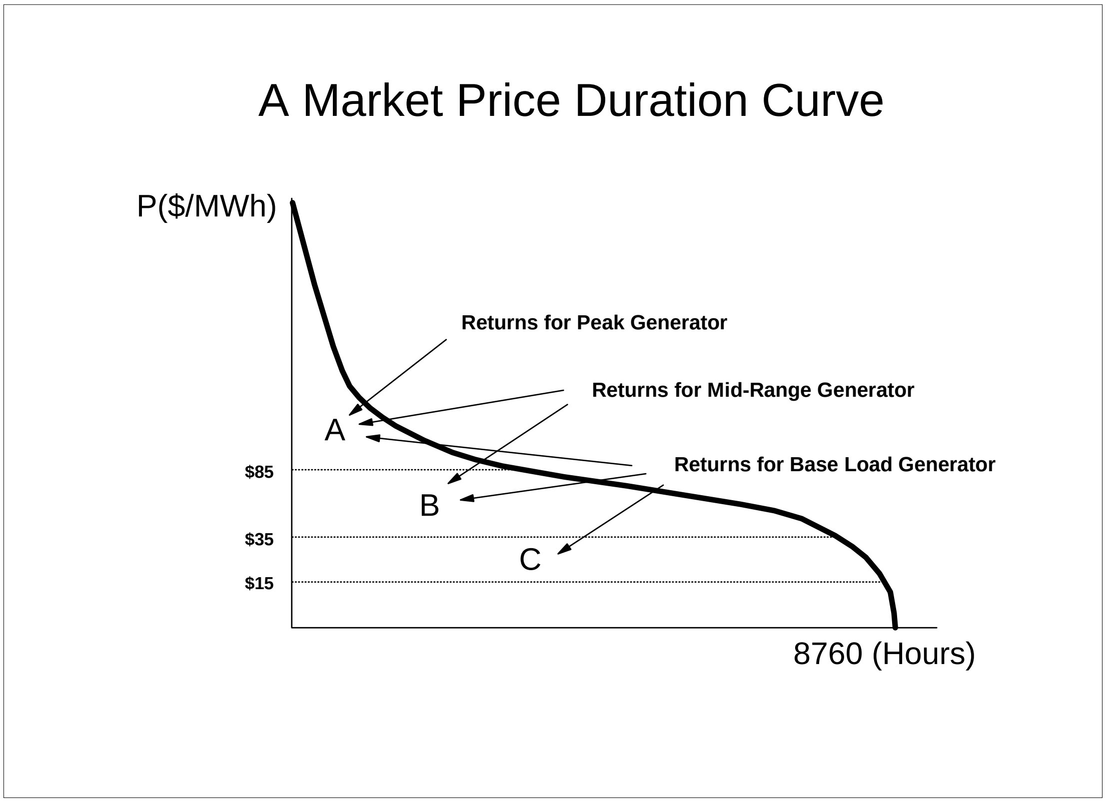

Figure 1

The mid-range generators (e.g., $35/MWh variable cost) would operate for many more hours, and the payments in area **A+B** would cover the larger fixed and investment costs of these plants. The lowest cost (e.g., $15/MWh variable cost) based-load generators would operate in virtually all hours but only rarely would the price fall to the lowest level. The combined area **A+B+C** would provide the payments for fixed and investment costs of base load generators.

The simplified graphic in Figure 1 illustrates the important point that in equilibrium the high prices during the peak hours provide part of the compensation needed for all generators, not just the peaking capacity. The magnitudes could be substantial. Although estimates vary, the approximate magnitude of area **A** would be on the order of $65,000/MW-year for a simple combustion turbine.[3] Hence, average peak prices of $1,000/MWh above operating cost would be needed sixty five hours a year in order to meet the payment requirements for peaking generation.

Introduction of administrative measures to limit the highest prices, such as through a price cap, would reduce payments available to all types of generating plants.

[3] PJM, State of the Market Report 2004, March 8, 2005, p. 82. Estimates for New York city could be twice as high.

As shown in Figure 2, the price cap creates the "missing money." This is the payment to generation that is eliminated as a result of the curtailment of prices. The administrative rules that produce the missing money include a variety of procedures. Explicit price caps are not the usual means of restraining prices. A more likely constraint on generator revenues would arise from an offer cap on generators to mitigate market power. In principle, mitigation through an offer cap need not create missing money. However, when the offer cap combines with a pricing rule that spot prices must be set by the highest (mitigated) offer for any plant running, the result can be capped prices and missing money. The problem would arise when the pricing rule does not fully account for the opportunity cost of incremental demand or incremental operating reserves during periods of scarcity. These opportunity costs at the margin could result in prices above the offer cap.

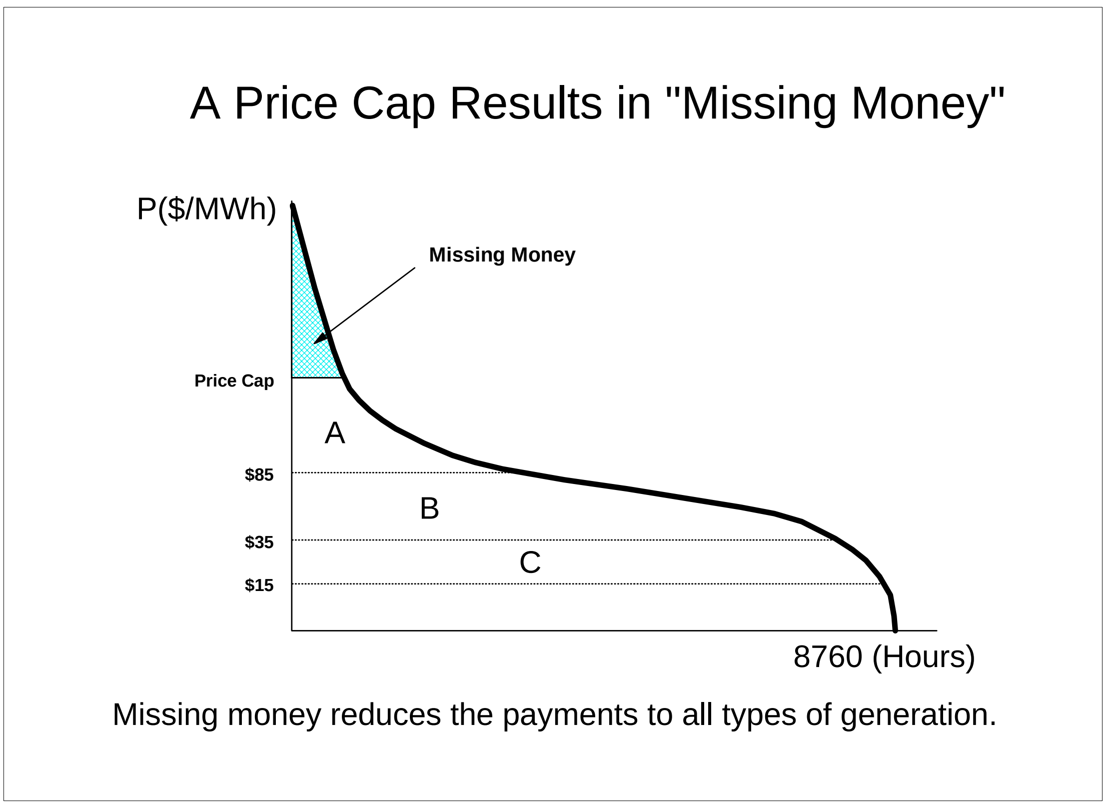

Figure 2

More indirect contributors to missing money would be reliability must run (RMR) units or out of market (OOM) dispatch, both of which involve use of expensive generating plants to meet load. However, various rules exclude these plants from consideration as part of the market and associated determination of prices. For example, the innovation of "soft" price caps institutionalized a device for keeping reported market prices low when real opportunity costs were higher. Collectively these rules produce the anomaly of constrained supplies and low prices.

The missing money goes hand-in-hand with "missing incentives." In the short run, the missing incentives complicate the task of the system operator in maintaining a secure dispatch. With prices disconnected from opportunity costs, market participants would have little incentive to act to enhance security and could face strong incentives to take actions, like leaning on the system to increase exports, which add to the security problems. A result is the need for ever more complicated rules to mandate behavior that is otherwise inconsistent with the incentives. As the rules mount up, the flexibility sought through markets can disappear. By now, it has been widely recognized that one of the principal advantages of locational marginal pricing systems is the alignment of participant incentives to support rather than oppose actions needed to manage congestion in the grid.[4] This role of reinforcing incentives to support reliability would be of greatest importance during periods of scarcity when the missing incentives arise.

The missing incentives extend to investment in new generation facilities or their substitutes. By some estimates the missing money amounts to a much as half or more of the $65,000/MW-yr payment required for new peak load generation investments.[5] It is this missing money that motivates interest in supplementary resource adequacy programs to provide a return to existing plants or support investment in new facilities. A direct approach to meeting the requirements of resource adequacy is to create a process beyond the energy market that provides added payments to generators who maintain or build needed generation facilities. Given an underlying assumption that administrative measures will necessarily be invoked to cap energy prices, and will always lead to insufficient payments in the energy market to maintain the desired level of capacity, the missing money leads inexorably to alternative approaches such as installed capacity (ICAP) requirements and related designs.[6]

The ICAP programs present a number of challenges.[7] For example, the assumption of a price-capped energy market implies that appropriate capacity choices must be identified by means other than market participants responding to the incentives provided through energy prices. This creates a need for central planning and greater prescription by regulators. Accordingly, regulators act on behalf of customers to take on more of the risks inherent in the long term investment decisions. When these details begin to emerge, participants recognize that this resource adequacy approach would recreate many of the features of electricity systems that were to be replaced by greater

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4 Phillip G. Harris, "Relationship between Competitive Power Markets and Grid Reliability: The PJM RTO Experience," Issue Papers on Reliability and Competition, US Department of Energy and Natural Resources Canada, August 2005, pp. 4-5. (www.energetics.com/meetings/reliability/papers.html)

5 Federal Energy Regulatory Commission, State of the Market Report, Washington DC, June 2005, p. 60.

6 For an extensive examination of this logic, see the workshops sponsored by the California Public Utility Commission, California Energy Commission and the California Independent System Operator at www.cpuc.ca.gov/static/industry/electric/installedcapacity/041004_instcapacity.htm. A summary of the arguments and subsequent recommendations appear in California Public Utility Commission, "Capacity Markets White Paper," Staff White Paper, CPUC Energy Division, August 25, 2005, (www.cpuc.ca.gov/word_pdf/REPORT/48884.pdf).

7 Scott M. Harvey, "ICAP Systems in the Northeast: Trends and Lessons," LECG, Report to the California ISO, September 2005.

reliance on restructured electricity markets. Inherent in this integrated planning process would be to shift a substantial portion of the investment risk and stranded costs back to customers who would be required to pay under the force of regulation.[8]

The usual argument that leads to this resurrection of integrated planning and regulatory driven investment begins with an assertion that the pure "energy only" electricity market behind Figure 1 is not politically feasible. If low price caps are imposed on the energy market, then something like a significant missing-money problem must follow. However, when the ICAP cure for the missing money problem starts to look worse than the disease, analysts of ICAP-type mechanisms revise this judgment and look more closely at a market design that does not breed the disease and hence does not require the cure.[9] This second look at an energy-only market design should not translate immediately into ignoring the underlying motivations for the administrative measures that constrain prices, such as the need to mitigate market power. But it would require refocusing attention on the policy ends and not the administrative means.

The ubiquitous reference to the missing-money problem found in resource adequacy proposals usually pays homage to the appeal of Figure 1 and the so-called "energy only" market. If only electricity prices could reach market-clearing levels defined by the opportunity costs, where there would be no administrative measures to cap prices and no missing money, there would be no need for administrative measures to supplement the payments to generators.[10] But if the highest spot prices would be too

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8 Bruce W. Radford, "Holes in the Market," Public Utilities Fortnightly, March 2005, pp. 19-21, 46-47.

9 For example, a series of workshops sponsored by the Public Utility Commission of Texas (PUCT) outlined this evolution of concern with installed capacity markets and return to interest in an energy-only approach. See www.puc.state.tx.us/rules/rulemake/24255/24255.cfm. A staff paper summarized many of the issues, Eric S. Schubert, "An Energy-Only Resource Adequacy Mechanism," Public Utility Commission of Texas, Staff White Paper, April 14, 2005. The staff subsequently recommended that the PUCT develop the details to "… provide for resource adequacy in ERCOT to be achieved through an energy only design." See Richard Greffe, Public Utility Commission of Texas, Wholesale Market Oversight, Memorandum, July 8, 2005. A similar direction appears in the Midwest Independent System Operator, "Discussion Paper on Resource Adequacy for the Midwest ISO Energy Markets," Draft, August 3, 2005.

10 Miles Bidwell, "Reliability Options," Electricity Journal, Vol. 18, Issue 5, June 2005, pp. 1. Eugene Meehan, Chantale LaCasse, Phillip Kalmus, and Bernard Neenan, "Central Resource Adequacy Markets for PJM, NY-ISO, and NE-ISO," NERA Final Report, New York, February 2003. Shmuel Oren, "Capacity Payments and Supply Adequacy in Competitive Markets," VII Symposium of Specialists in Electric Operational Systems Planning," Basil, May 2000. Shmuel Oren, "Ensuring Generation Adequacy in Competitive Electricity Markets," University of California at Berkeley, April 2004. Shmuel Oren, "Capacity Mechanisms for Generation Adequacy Insurance," CPUC-CEOB-CAISO Installed Capacity Conference, San Francisco, California, October 4-5, 2004. Roy J. Shanker, "Comments on Standard Market Design: Resource Adequacy Requirement," Federal Energy Regulatory Commission, Docket RM01-12-000, January 10, 2003. See also Roy J. Shanker, "Comments," Federal Energy Regulatory Commission Technical Conference on Capacity Markets in the PJM Region, June 16, 2005. Harry Singh, Call Options for Energy: A Market Based Alternative to ICAP and Energy Price Caps," PG&E National Energy Group, October 16, 2000. Steven Stoft, Testimony on Behalf of ISO New England on Locational Installed Capacity Market Proposal, Submitted to Federal Energy Regulatory Commission, Docket Number ER03-563-030; Direct August 31, 2004; Supplemental November 4, 2004; Rebuttal February 10, 2005. Carlos Vázquez, Michel Rivier, and Ignacio J. Pérez-Arriaga, "A Market Approach to Long-Term Security

high, so the argument goes, the exposure of customers would be unacceptable and the energy-only market could never work. Typically, the design of an energy-only market is dismissed without further consideration.[11] The discussion of an energy-only market ends there, and attention turns to ICAP design in its many forms.

When frustration with the implications of ICAP markets sets in, the possibility arises to give more serious attention to how an "energy only" market might operate and what would be needed to make the transition. To revisit this issue and consider the ends rather than the means requires a greater specification of such a market in order to understand what would be included in the basic elements and what problems might remain that could motivate an interest in modifications of an energy-only market approach to resource adequacy.

Energy-only Market Design

There are many appeals to an idealized vision of an energy-only market, but there is little description of the key features. The assumptions of the idealized vision do not describe real systems. For example, high spot prices raise the specter of market power, and it is difficult to step back from this reality and describe a market without the exercise of market power. Hence, the discussion of design elements quickly detours from consideration of the core features of an idealized energy-only market. The intent here is to avoid this detour long enough to sketch out the principal elements. The discussion here assumes competitive behavior and no transaction costs, but returns to these issues later in discussing potential problems with an "energy-only" market design.

A core idea of an electricity market that relies on market incentives for investment is that these incentives appear through the largely voluntary interactions of the participants in the market. A main feature of the market would be prices determined without either administrative price caps or other interventions that would depress prices below high opportunity costs and leave money missing. The real-time prices of electric energy, and participant actions, including contracting and other hedging strategies in anticipation of these prices, would be the primary drivers of decisions in the market. The principal investment decisions would be made by market participants, and this decentralized process would improve innovation and efficiency. A goal would be to avoid repeating the problem of leaving customers with stranded costs arising from decisions in which the customers had no choice. This change in the investment decision process and the associated reallocation of risks would arguably be the most important benefit that could justify greater reliance on markets and the costs of electricity restructuring. If this were not true, and if it would be easy for planners and regulators to

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of Supply," IEEE Transactions on Power Systems, Vol. 17, No. 2, May 2002. Carlos Vázquez, Carlos Battle, Michel Rivier, and Ignacio J. Pérez-Arriaga, "Security of Supply in the Dutch Electricity Market: the Role of Reliability Options," Report IIT-03-084IC, Comillas, Universidad Pontifica, Madrid, Draft Version 3.0, Madrid, December 15, 2003.

[11] "Energy-only" markets of different designs exist in Alberta, Australia, New Zealand and Europe. The lessons there are relevant, and the resource adequacy issue is not fully resolved. However, the differences in context and details would take the discussion further afield from the U.S. setting.

lay out the trajectory of needed investment for the best portfolio of generation, transmission and demand alternatives, then electricity restructuring would not be needed.

A central concern of the growing doubts about the direction of development in administrative installed capacity markets is the loss of this critical reallocation of decisions away from regulators and towards market participants. The increasing scope, increasing detail and increasingly longer horizons of ICAP programs establish an evolutionary path with no end in sight.[12] It is not the capacity construct *per se* that should be of concern. For example, operating reserve capacity requirements are an essential part of electricity systems. Rather it is the scope, duration and detail of mandatory ICAP obligations that are imposed by the central planner, and the corresponding shift of the locus of investment risks decisions away from the market with the decisions made under the central plan and the risks assigned back to captive consumers.

The changes reverberate through the market design, transforming the original role of the system coordinators, the Independent System Operator (ISO) or Regional Transmission Organization (RTO): "the ISOs/RTOs are not *principals* ***in*** *the market* but rather *service providers* ***to*** *the market*. … Creating a forward looking capacity construct is therefore potentially not 'just' an incremental increase in responsibilities for an ISO or RTO; but rather it is a significant structural change to the role they currently perform."[13] In effect, the effort to compensate for capped spot prices recreates the regulatory integrated resource planning process that was to be replaced by more decentralized market decisions. This movement to create centralized investment decisions according to long-term requirements set by the ISO follows directly from the missing incentives of the price-capped energy market. Hence, any effort to support market decisions and avoid mission creep at the ISO must then provide the missing incentives through market-based prices rather than administrative substitutes. An essential feature of an energy-only market design would be efficient spot pricing to reflect opportunity costs.

Just as important as embracing market-driven spot pricing is a recognition that an energy-only market does not assume or require that all transactions be limited to the spot market. To the contrary, a robust energy market with realistic real-time prices would permit and encourage long-term contracting of a variety of forms to reflect the conditions and relative risk preferences of the market participants. The major economic decisions surrounding investment and most of the actual transactions might and could be made with long-term contracts voluntarily arranged by the parties. Market participants might choose voluntarily to enter into ICAP type contracts, but this would be only one of the possible contract forms. However, even if spot-market transactions were reduced to a small volume for balancing and congestion management, expectations regarding future spot prices created by uncapped energy pricing in the spot market would be essential and would be reflected in the terms of forward contracts.

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[12] Craig Hart, "Capacity Markets: A Bridge to Recovery?", Public Utilities Fortnightly, May 2005, pp. 24-27.

[13] Midwest Independent System Operator, "Discussion Paper on Resource Adequacy for the Midwest ISO Energy Markets," (emphasis in the original), Draft, August 3, 2005, pp. 1-2.

Similarly, the emphasis on an "energy only" market does not mean that there would be nothing but spot deliveries of electric energy with a complete absence of administrative features in the market. Since the technology of electricity systems does not yet allow for operations dictated solely by market transactions with simple well-defined property rights, the system requires some rules to deal with the complex interactions in the network. To the contrary, there would of necessity be an array of ancillary services and associated administrative rules for such services. For instance, the existing technology for electricity requires that system security be met by providing operating reserves in generation in order to meet the possible contingencies. The required level and configuration of these operating reserves are not determined in a market. The operating reserve requirements are based on prior studies and experience of what resources would be needed and where they would be needed over the next minutes or hours of the dispatch in order to protect against both involuntary load shedding and more serious dangers of system collapse.

Other examples include the rules for providing contingency security constraints for transmission, and various ancillary services that are inherently administrative, even though they may be designed with an economic component included. The goal of the energy-only market is not to eliminate all administrative rules. Rather a goal is to design the rules, pricing and implied incentives to support operating and investment decisions made by market participants in response to the forces in the market.

In the discussion below, the emphasis is on providing electric energy with the critical operating reserves as the representative ancillary service. For the initial discussion, it is assumed that there are no locational issues and the design sketch applies as though everything occurred at a single location. The discussion illustrates the principles that would apply to implementation in a network with transmission constraints and locational requirements.

Demand

The energy-only market begins with the real-time demand for energy in the wholesale market. In order to capture some of the features of the real system, the demand for electricity shown in Figure 3 divides into two segments. The inflexible demand represents the customers that are assumed not to have individual real-time meters or real-time individual controls. It is not possible for these customers to receive or respond to the incentives provided by real-time prices. Typically these customers pay a fixed price over the period, here assumed to be $30/MWh. Of course, these customers have some implicit demand curve and the load that results at $30 is the load assumed to apply no matter what the spot market conditions.

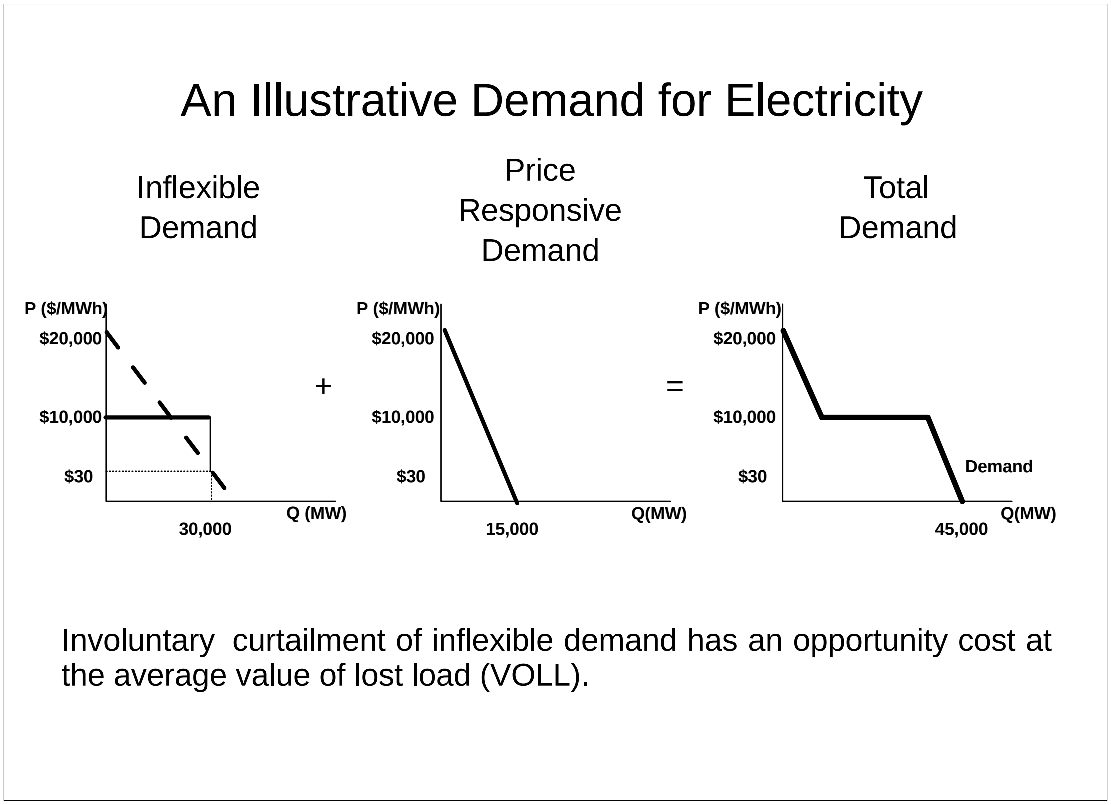

Figure 3

Inflexible demand would maintain this load level unless conditions became severe enough that the system operator must intervene. In this event there would be involuntary curtailment through rolling blackouts or brownouts. The simplifying assumption for the illustration is that the lack of metering and individual controls limits the system operator to random, or at least proportional reductions of inflexible loads. The individual inflexible customers could not be dispatched or metered separately, but the load of the group could be reduced by curtailing all the loads proportionally. Since the price the customers will be paying may still be $30/MWh, this would perforce be involuntary curtailment. The average opportunity cost of the involuntary curtailment would be the average "value of the lost load" (VOLL) defined by the implicit demand curve, which represents the correct estimate of the cost of curtailment given the limits on control of inflexible load. This average VOLL is assumed to be $10,000/MWh in the example. Of course, some of these customers would be willing to pay more, but some who are curtailed would also be prepared to be curtailed for much less than the average opportunity cost. Under the circumstances, the marginal cost of curtailment for the inflexible group is the average cost of the involuntary curtailment, $10,000/MWh.[14]

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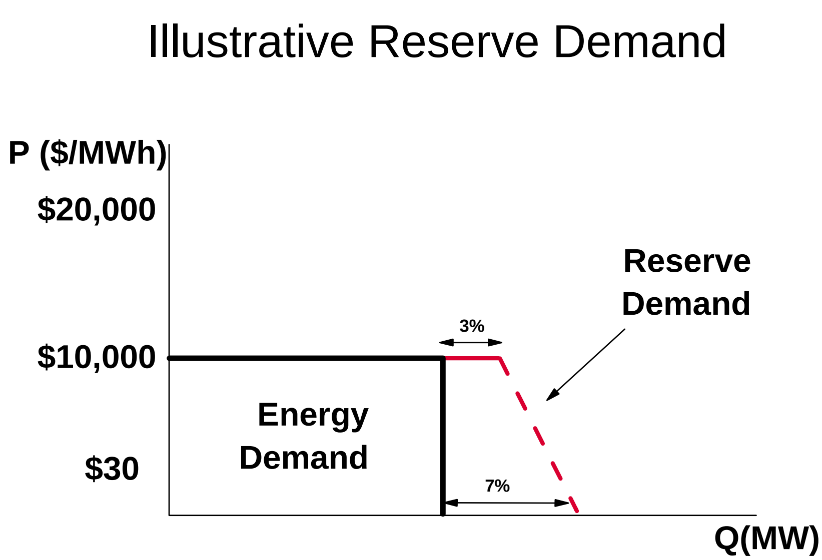
[14] Steven Stoft, Power System Economics, IEEE Press, 2002, p. 149-150.

Who provides this estimate of average VOLL? Absent some means of credible declaration by the customers, this implicit demand curve would be estimated by regulators or by the system operator. Hence, there would be an administrative determination of what should serve as the average VOLL. This average VOLL price and the proportional curtailment in effect convert the implicit demand curve of the inflexible load into a horizontal demand curve as shown in the left panel in Figure 3.

By contrast, the flexible load would have appropriate metering and control. The control might arise through the dispatch actions of the system operator or through the decentralized choices of the loads given their estimate of prices. These flexible customers would be able to bid demand in real-time and follow signals to reduce or increase load when prices were high or low. This demand curve would arrive naturally through the bids or choices of the load, and would require no further determination by the system operator. The combination of the two demand curves through horizontal addition as illustrated in Figure 3 results in the demand for the electricity to be delivered to the customers.



There is a minimum level of operating reserve (e.g., 3%) to protect against system-wide failure. Above the minimum reserve, reductions below a nominal reserve target (e.g., 7%) are price senstive.

Figure 4

A characterization of electric energy demand would not complete the demand story. In addition to the electric load at any moment, the system operator must obtain an appropriate level of operating reserves. For instance, Figure 4 illustrates operating reserves determined according to two rules that would combine to provide a reserve demand curve in this energy-only market. To isolate the reserve demand curve, take the level of energy demand as fixed. First assume there is a minimum level of reserve, set here at 3%. The criteria for determining this minimum requirement would be an issue, but is not the point of the discussion here. The constraint could be taken directly from established minimum reserve requirements set by the North American Electric Reliability Council (NERC). Some minimum is needed, for example, to prevent catastrophic failure through a widespread and uncontrolled blackout in the system. The exact level is not important for the illustration, and we return to this issue later. What is important for the energy-only market design is that this minimum level conforms to the actions of the system operator. The system operator would not go below this level of reserves even if this required involuntary curtailment of inflexible load. This level of operating reserves is shown as the solid red line in Figure 4.

Above this minimum level of operating reserves, there would be more flexibility. Other things being equal, it would be better to have more operating reserves. But if energy demand increased the operator would not impose involuntary curtailments in order to maintain a higher level of operating reserve. Under the traditional system, a system operator would reduce operating reserves and turn to load shedding only as a last resort. To do otherwise would be to impose involuntary load shedding with certainty in order to avoid a contingent probability that involuntary load shedding might be required. Hence, recognizing that there is some flexibility in operating reserves is nothing new. What would be different than the traditional approach would be to identify the cost of reduced reserves. [15]

This would provide the second piece of the operating reserve demand. There is a tradeoff that would consider the marginal change in the expected loss of load, valued at the average VOLL, to define the willingness to pay for incremental reserves. Beyond the minimum level of reserves there would be a nominal reserve target, which for the illustration in Figure 4 reaches 7% of capacity above load if the reserves were free. However, at reserve levels above the minimum requirement the operator would not be willing to institute involuntary load curtailments and would instead accept operating reserve levels less than the target level if load were high and reserves were not freely available and free. In this range, as reserves levels approached the minimum level, the price would be increasing for operating capacity needed to meet energy load plus reserves. This is the price sensitive part of the operating reserve demand illustrated by the dashed red line.[16]

Setting operating reserve schedules over the next minutes or hours is a regular activity of system operators. Since the configuration of load and installed generation would already be known or relatively easy to predict, the task of scheduling suitable

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[15] Steven Stoft, Power System Economics, IEEE Press, 2002. p. 112-113.

[16] The reserve price would be the energy price net of avoided costs plus any spinning costs. There would be an interaction between the demand for energy and the demand for operating reserves. Strictly speaking, therefore, the simplified graphic with the dashed line captures the effect of reserve demand on energy price in the simultaneous clearing of energy and reserve markets.

operating reserves requires much less information than would parallel attempts to specify required installed capacity many months or years in advance. For operating reserves, there would be substantially less uncertainty and the dispatch could be updated quickly as conditions change. This is a familiar exercise for system operators. Equally familiar is the practice of accepting lower reserve levels during periods of generation scarcity relative to load requirements.

Less familiar would be the practice of translating these reduced reserve levels under increased scarcity into economic terms to reflect the implied higher opportunity costs. [17] Although reserve demand curves have been implemented by the NYISO, the experience with explicit demand curves linked to high average VOLL is limited. This additional step to price reserves according to a reserve demand curve would be included as part of implementation of the energy-only market sketched here. The reserve demand curve would be made explicit and included as part of the simultaneous implementation of the energy and reserve dispatch.

The absence of an appropriate operating reserve demand curve is one of the difficulties in market designs that result in *de facto* price caps and missing money. With little explicit energy demand bidding and no recognition of an operating reserve demand curve, the pricing rules default to the most expensive generator offer. With mitigated offers, this can result in a generator running at capacity and price being set at the variable cost with no scarcity rent, even when reserves are reduced. A reserve demand curve would improve the determination of prices in these scarcity conditions. However, if the reserve demand curve does not raise prices towards the average VOLL when operating reserve levels approach the minimum reserve level, then the demand curve is not capable of representing the effects of scarcity or capturing the true opportunity cost at the margin. If the pricing algorithms do not incorporate a demand effect, whether through participants' energy demand bids or through the simultaneous interaction with the operating reserve demand curve, the resulting price determination would be flawed in the periods of scarcity when it would be needed the most. If the price is always set at the running cost of the most expensive generator included in the dispatch, then either there is never any time when capacity is constrained or the pricing calculation is based on a misunderstanding of the meaning of short-run opportunity cost. The operating cost of the most expensive unit running is relevant when there is excess capacity. However, when capacity is short and generation supply is in effect fixed over the range, the demand curve for energy and operating reserve should set the price, and should be able to set the scarcity price at a high level.

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[17] Steven Stoft, Power System Economics, IEEE Press, 2002. pp. 197-200.

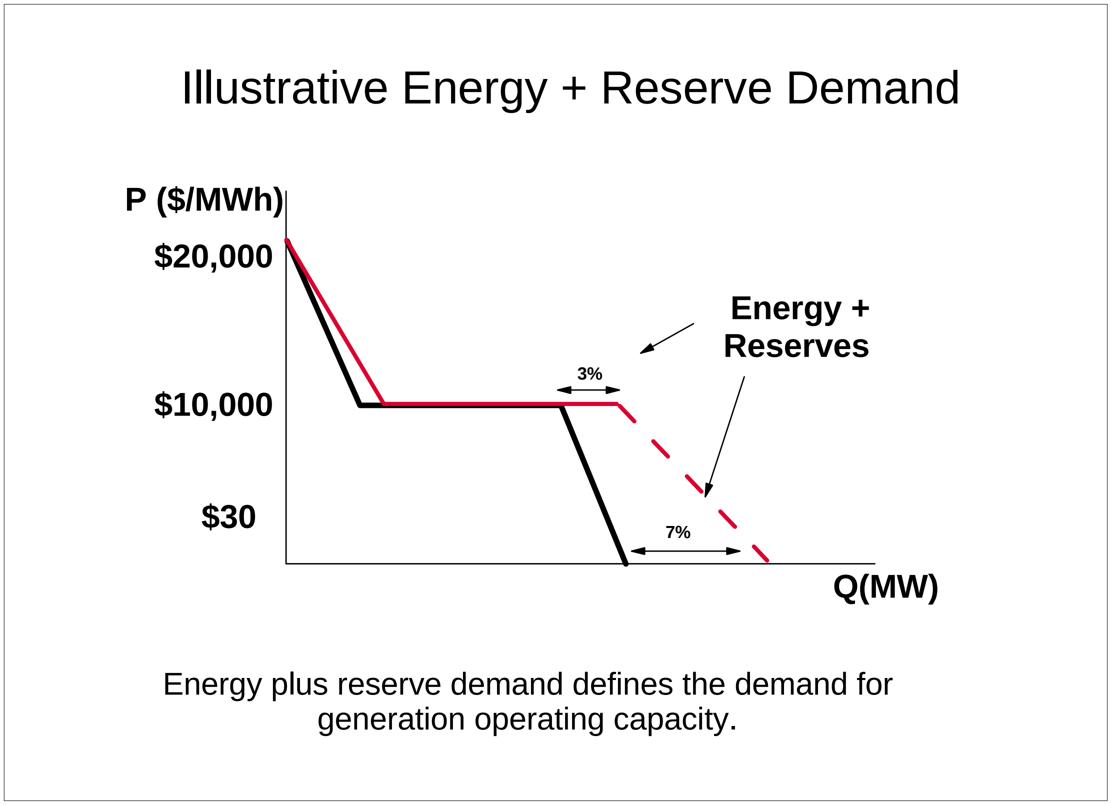

Figure 5

This price sensitivity for operating reserves provides an added slope for operating capacity demand between the minimum requirement and nominal target. When combined with the price sensitive energy demand, Figure 5 summarizes the total demand for energy and reserves. As the market tightens relative to available supply, reserves would be reduced and prices for energy and reserves would rise. When operating reserves reach the minimum level, the price reaches the $10,000/MWh average VOLL and involuntary load curtailments would be required

Supply and Pricing

On the supply side, the system operator would receive offers of available generating capacity with prices for energy and reserves. The system operator would use the load bids and generator offers to determine a bid-based, security constrained, economic dispatch (with locational prices) in the usual way. This would include both bilateral schedules and spot market imbalances priced at the equilibrium market price. During normal operating conditions with moderate load and a high degree of available generating capacity, the system operator would obtain the market equilibrium for energy at a relatively low price. Operating reserves would be well above the minimum level. This equilibrium condition is illustrated in Figure 6. All loads and all generation would clear imbalances at these energy prices. All generators providing operating reserves would be paid the market-clearing price for reserves at the energy price less the avoided variable costs of generation. Under the assumed design here, operating reserve requirements would not be attributable to individual customers, and all loads would be charged a contemporaneous uplift payment to cover the cost of operating reserves and other ancillary services.

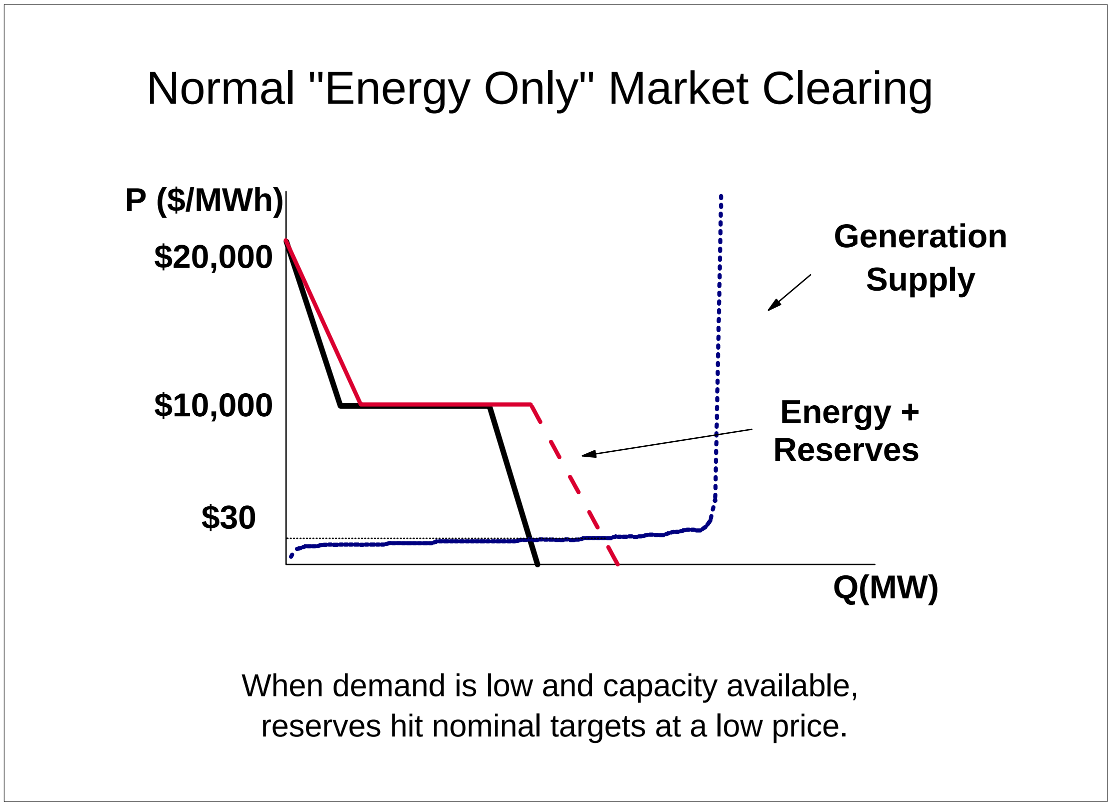

Figure 6

Under stressed conditions there would not be adequate capacity to meet all load and maintain the target nominal level of reserves. This would give rise to scarcity pricing determined by the capacities of the generation offered, the energy demand, and the administrative demand for operating reserves. As shown in Figure 7, the resulting price would be high, here illustrated as $7,000/MWh for energy and essentially the same market-clearing price for operating reserves. This would approach the average VOLL. Flexible customers with real-time metering would respond to the high price signals by reducing load. The system operator would make the decisions to reduce the level of operating reserves. The resulting equilibrium prices again would apply to all imbalances relative to bilateral schedules. Payments for operating reserves would be made to generators providing reserves and the cost would be applied to loads in a proportional uplift payment. All generators providing energy would receive the high energy price. All generators providing reserves would receive this high energy price less the variable cost of the marginal reserve capacity. Although scarcity conditions with very high prices would apply in relatively few hours, the payments to generators during these hours would include a large fraction of the total contribution to fixed and investment costs.

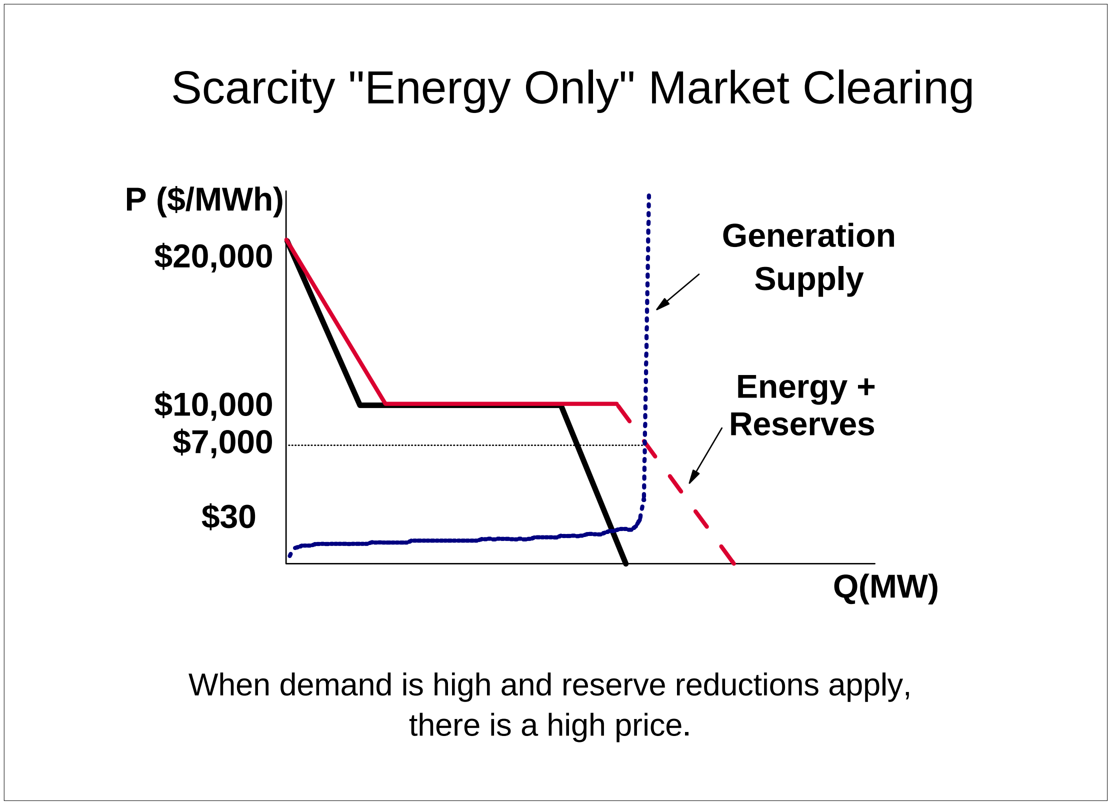

Figure 7

High energy prices during scarcity conditions would approach the average VOLL. If the degree of scarcity reaches the point that reserves are reduced to the minimum operating level, the system operator would turn to random or rotating involuntary load curtailments for the inflexible load. Under these conditions the price of energy would be at the average VOLL, with a corresponding price of reserves. This would continue over the full range of the inflexible load indicated by the horizontal segment of the demand curve in Figure 8. Customers with very high valuations (those above the average VOLL) would have the ability and the incentive to install the meters and controls allowing for real-time pricing to ensure they were not included as inflexible load. Thus the system could produce higher reliability levels for those who would be willing to pay above the average VOLL. However, except when *all* inflexible load would be curtailed, the equilibrium price would not rise above the administratively determined average VOLL. In real systems, curtailing all inflexible load with resulting prices going above the average VOLL would be highly unlikely.

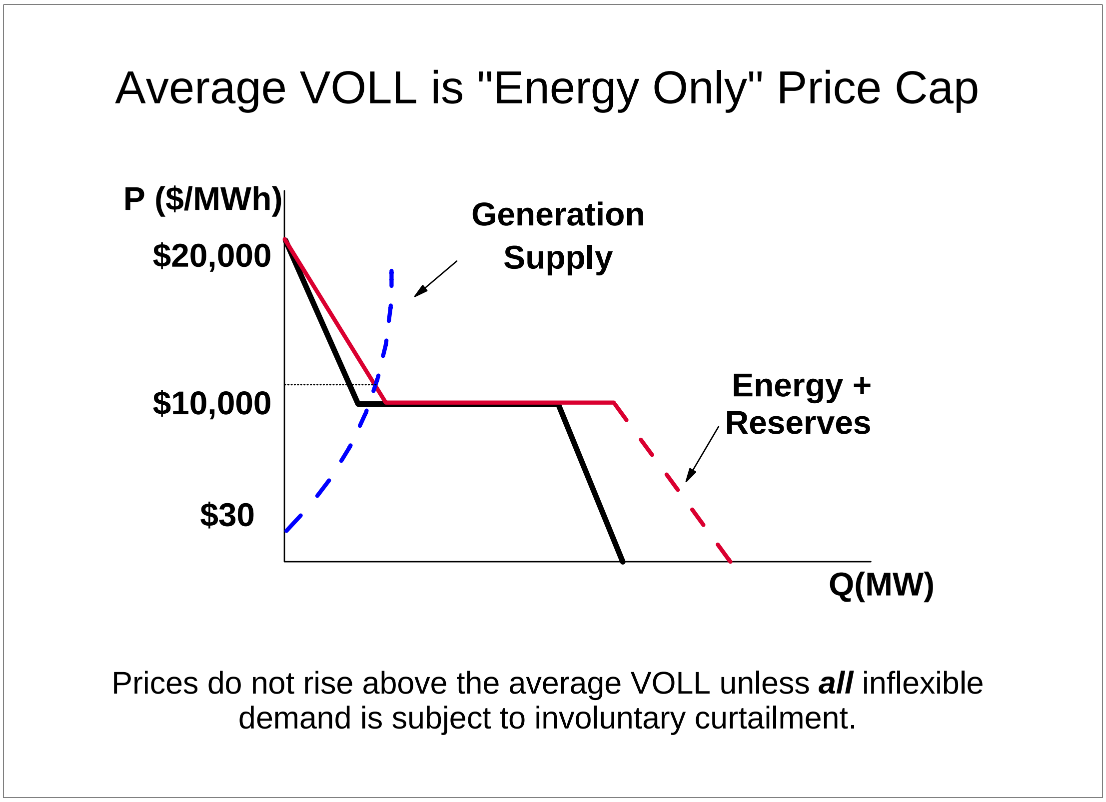

Figure 8

In this sense, it might be natural to refer to the average VOLL as a price cap. Although this is true in the sense of a prediction, it is worthwhile to emphasize that this would not be a price cap in the usual meaning. As discussed above, the average VOLL is the proper measure of the opportunity costs of the involuntary curtailments. Unlike with the usual price cap at a low price, the system operator would not have any offers for generation above this price that should be accepted. There would be no room for and no need for OOM purchases in their many forms to obtain additional energy or to reduce other load in order to avoid the involuntary curtailment. The average VOLL would set the appropriate market price when involuntary load curtailments were required.

The emphasis on connecting the energy and operating reserve demand curves to the average VOLL is not to ensure that this price will be reached often or that curtailments of inflexible load would be common. With an appropriate implementation of the operating reserve demand curve, the opposite would be true. Prices should be higher than in the capped market, but should seldom rise to the level of the average VOLL. The response in the market would obtain more demand response and investment in new capacity. It is the intermediate price responsive segment of the demand curve that would be important, and the connection to the average VOLL provides the anchor at the high end.

With the expected range of supply and demand conditions spanned by the illustration in Figure 6 and Figure 7, the "energy-only" market should produce a distribution of prices as illustrated in Figure 1. In long-run equilibrium, there would be no missing money. Market prices would provide the needed incentives for loads and generation. All loads and generators would settle imbalances relative to bilateral schedules at the market equilibrium price. Prices would at times be volatile, varying substantially over the day and over the seasons. For some hours, prices would be very high.

The anticipation of these uncertain and sometimes high prices would create strong incentives for market participants to contract forward. Under the idealized assumption of no transaction costs, contracts would arise to cover a substantial portion of all load and generation. The precise terms and prices embedded in these contracts would be determined according to the preferences of the market participants. In principle, neither the system operator nor the regulators need observe these contracts nor approve the terms.

Since there would be no missing incentives, there would be no need to devise operating rules to compel competitive actors to act against the incentives they face. Since there would be no missing money, there would be no need for resource adequacy programs designed to provide the missing money. Both generators and loads would be hedged through the forward contracts. Hence, there would be limited exposure to the volatile spot prices. These volatile prices and the price duration curve in Figure 1 would be critical to success of the energy-only market, but the limited exposure to high prices should not provide a critical mass of political pressure to induce further intervention in the market.

Energy-only Market in a Network

The simple energy market depicted in Figure 6 and Figure 7 illustrates the ideas in the context of a single period at a single location. The real system would involve many locations connected by a network and multiple periods. The resulting design would have the now familiar core features of the organized RTO markets.[18] The centerpiece would be a spot market organized as a bid-based, security-constrained economic dispatch with locational (nodal) prices as in Figure 9. The energy-only market includes bilateral schedules at the difference in the locational prices. Transmission hedges appear in the form of financial transmission rights designed congestion revenue rights (CRRs).

[18] See the CAISO Market Redesign and Technology Upgrade Program (MRTU), www.caiso.com/docs/2001/12/21/2001122108490719681.html.

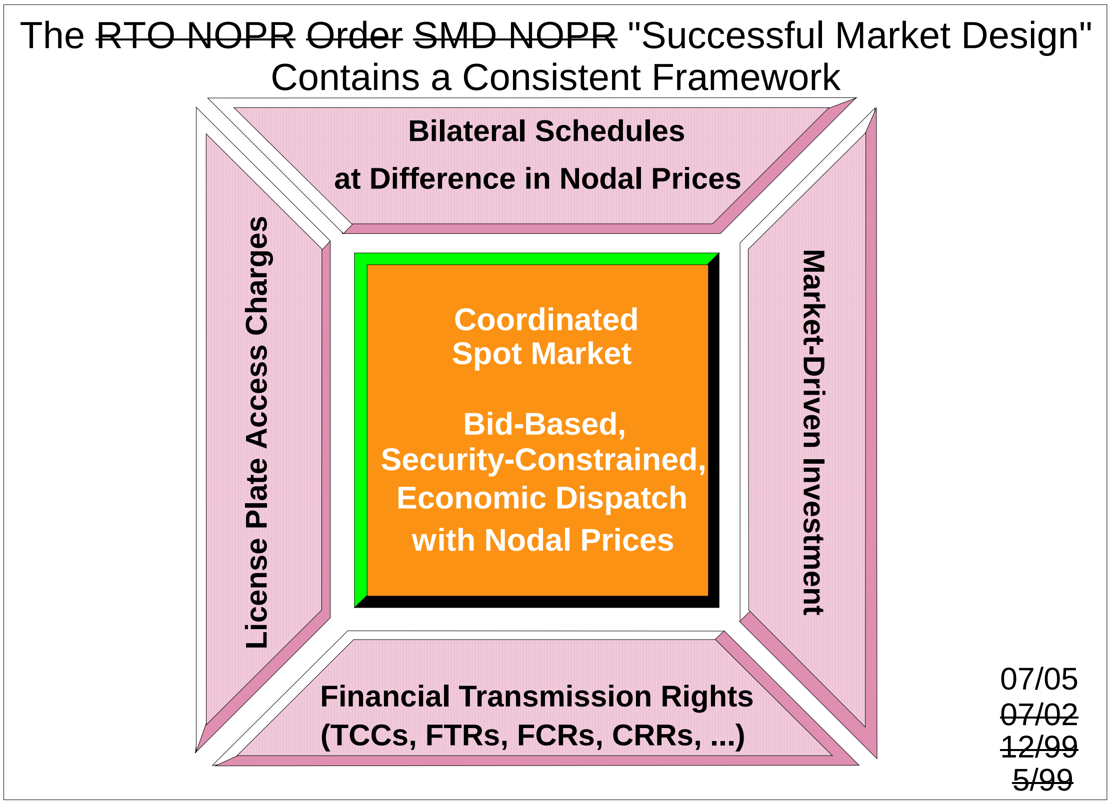

Figure 9

The real-time market could be combined with one or more forward markets such as the day-ahead market (DAM) with the same basic structure supplemented with virtual bids and schedules relative to the real-time market. This day-ahead market could include both a dispatch and a unit commitment process.

As is common, the unit commitment could be supported further by a reliability unit commitment (RUC) process in which the system operator's day ahead forecast would be checked and additional units committed as needed to ensure reliability. The RUC units would receive a bid-cost guarantee if the realized revenues in the energy market were not as large as the bid costs. The RUC is an example of a largely non-market administrative rule driven by reliability requirements but structured in a way to support the remainder of the energy market. The RUC would not involve forward procurement of energy beyond minimum output levels, and hence would not undermine the incentives in the DAM. The same arguments and rules that apply in the current RUC implementations would carry over in the energy-only market design.

The requirements for operating reserves, expressed as location specific operating reserve demand curves, would apply as is now done in the RTO markets. Typically there would be some regional aggregation at a greater level than the individual nodes, and operating reserves must meet certain requirements in that region. Hence, congestion management would require finer nodal specification and pricing, and there would be a different set of aggregation rules for different types of operating reserves. Although the resulting model does not lend itself to the simple graphical addition of demand curves in the stylized illustrations above, there is nothing unusual about including operating reserves in the model with the appropriate mix of aggregation and rules that link reserves to nodal load and generation activities in a network. The resulting locational energy and reserve prices would be obtained through simultaneous optimization of energy and reserve dispatch with pricing to minimize the reliance on uplift payments.[19] The main innovations of the energy-only market design would be in the configuration of the reserve demand curves, connection to the average VOLL, and elimination of *de facto* price caps. In addition, this should eliminate the need for most or all OOM purchases.

Energy-only Market Defects

The outline of an energy-only market, with the necessary administrative rules structured to support market decisions, would raise concerns with regulators and others regarding its promise of providing efficient results and adequate investment. To some analysts the absence of the missing money problem might signal the presence of other market design defects. Further, since the idealized assumptions would not hold exactly in a real system, potential problems could undermine the workability of any attempt to approximate an energy-only market. Here we consider first issues like demand response, reliability and missing markets that could be addressed in principle within the energy-only framework. Market power would be more difficult to mitigate without regulatory intervention, but it is possible to design compatible regulatory interventions that would not disrupt basic operation of the market. A difficult problem would be a lack of forward contracting given both transaction costs for customers and regulatory rules that limit the incentives of load serving entities. A concern with inadequate contracting touches directly on the resource adequacy issues associated with the missing money problem.

Demand Response

The generic demand characterization in Figure 3 includes flexible load that responds to price. A conclusion might follow that an energy-only market would require a substantial degree of formal bidding for dispatchable energy that a system operator could use to respond to scarcity conditions. If there were little or no flexible loads, then prices would bounce between the low operating costs of generators and the high average VOLL. Hence, there is often an assumption that substantial energy demand response would be a prerequisite of an energy-only market implementation.

It is a commonplace that electricity markets would work better with more demand response. This is true of the energy-only market design just as it is true in a price-capped design. Under an energy-only approach there would be more, perhaps much more, incentive for load to acquire the necessary meters and take action to reduce demand during periods of scarcity and the associated high prices. However, despite the benefits, greater demand bidding is not a prerequisite of an energy-only market design.

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[19] William W. Hogan and Brendan J. Ring, “On Minimum-Uplift Pricing For Electricity Markets,” Center for Business and Government, Harvard University, March 19, 2003, (www.whogan.com) .

Strictly speaking, for successful operation of market clearing it would not be necessary that load formally bid into the dispatch. With regular calculation and publication of locational prices, loads could follow the current conditions and make short term forecasts. Loads could adjust their consumption in response to actual or expected real time prices without actions being taken by the system operator. If the metering for real-time load is in place and consumption is settled at real-time spot prices, demand could respond to real time prices without receiving dispatch instructions from the ISO.

Furthermore, a large energy demand response is not a requirement to avoid the binary price outcomes under perverse examples with prices bouncing from low operating costs to the high average VOLL. Such outcomes require that there be no price response in the total demand for energy *and* the demand for reserves. However, as illustrated in Figure 5, even if there were no flexible energy demand response there would by construction be a price response associated with the demand for operating reserves. Of course, energy demand response would be valuable. For any level of capacity that provides a given level of reliability, there is some set of shortage prices that would produce generator revenue streams that if correctly anticipated would be sufficient to sustain that level of capacity.[20] If there is a potential for error in setting these shortage prices or for error by suppliers in translating these shortage prices into expected income, then the amount of energy demand response is a cushion against load shedding arising from errors in estimating future prices and the profitable level of capacity.

There is also less potential for error if the ISO can set an operating reserve demand curve, rather than just shortage prices for reserves, so that small errors in setting shortage prices do not drive the system too far from the expected equilibrium level of prices. And it doesn't take much of a response to move away from a system where prices bounce between the lowest to the highest level towards a system where the prices, while volatile still, trace out a more "normal" response to market conditions.

Hence, while it would be difficult to implement a pure energy-only market with no energy demand response and no pricing of reserves, once operating reserves are included in the "energy-only" market design the same conditions would not apply. More energy demand response would be better, but the energy demand response cart could come after the horse of efficient "energy-only" market design applying an operating reserve demand curve and simultaneous pricing of energy and operating reserves.

Reliability

An energy-only market design defines and prices reliability through the demand for operating reserves. It would be possible to estimate the resulting loss of load probability to compare with the traditional planning standard of one day in ten years for a loss of load event. But the expected loss of load probability would be an output of the market choices more than an input to system design.   If the operating reserve demand curve properly reflected the value of reserves, the "correct" loss-of-load probability would follow automatically.

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[20] Steven Stoft, Power System Economics, IEEE Press, 2002, pp. 167-168.

In a market context, the concept of reliability differs for the two types of demand. In the case of inflexible demand, any interruption of service would be involuntary. This would conform closely to the traditional situation where the planning criterion assumed a given and fixed load and the probability that adequate generation would be available could be calculated. However, for flexible price-responsive demand the same concepts would not apply. As the market tightens and prices rise, flexible demand reduces and this by definition would not be an involuntary loss of load. Reliability becomes reliability at a price for the flexible demand.

Different levels of installed capacity would imply different prices and a distribution of probabilities for any involuntary loss of load. This would be true in both an energy-only market and in a price-capped market.[21] Given the demand curve for operating reserves, the expected long-run equilibrium loss of load probability could be more or less than any given planning standard. To the extent that there is a difference, it might be argued that the demand for operating reserves should be adjusted to match the planning standard.

However, an alternative interpretation would be that the operating reserve demand curve provides the better representation of the appropriate level of reliability. The direct consideration of the value of operating reserves captures the tradeoff that could be included only indirectly in the traditional planning standard. For example, suppose the equilibrium loss of load probability that would result from a given operating reserve demand curve would be higher than the under the traditional standard at the target level of installed capacity. This might be argued to require an increase in the demand for operating reserves in order to increase reliability. In effect, this argument would say that the price of reserves should be higher than the tradeoff defined by the operating reserve demand curve. But this argument would contradict the definition of the demand curve. If the operating reserve demand curve captures the value of reliability, the resulting expected equilibrium loss of load probability should be the standard.

This stands in contrast to an alternative approach that would fix the installed capacity requirement and determine the operating reserve demand to produce enough revenue to support investment that would meet the installed capacity target. In an energy only market, or in a price capped market, it would always be possible to set the operating reserve requirement at a level that met the expected revenue requirement and eliminated the missing money problem for a given level of installed capacity.[22]

The indirect route of specifying the expected loss of load probability should not replace the direct determination of the willingness to pay for operating reserves. If the expected loss off load probability were less than the traditional planning standard, a

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[21] For an analogous discussion in the context of the ISONE LICAP design, see Steven Stoft, Testimony on Behalf of ISO New England on Locational Installed Capacity Market Proposal, Submitted to Federal Energy Regulatory Commission, Docket Number ER03-563-030, Rebuttal February 10, 2005, pp. 35-36..

[22] The energy-only operating reserve demand curve is not derived from a revenue target. The combination of energy demand and reserve demand reflects the value of the energy and reserves. This is distinct from the illustrative dichotomy between VOLL pricing and operating reserve (OpRes) pricing described in Steven Stoft, Power System Economics, IEEE Press, 2002, pp. 108-200.

similar argument would give deference to the operating reserve demand curve. Hence, while an estimate of the distribution of loss of load probabilities might inform the design of the operating reserve demand curve in judging the adequacy of reserves, by forcing questions about the realism of the operating reserve demand curve, any conflict between the two would ultimately be resolved in favor of the operating reserve demand curve. Once the willingness to pay for operating reserves is made explicit and accepted by the regulators and system operator, there would be no need to further reconcile the expected loss of load probability with the operating curve demand curve.

Other things being equal, use of the energy-only market design should reduce the cost of meeting the reliability requirements. The flexible demand provides an important added tool to meet reliability standards. The demand response should be more than found in traditional utility systems or that could be provided in price-capped markets. Without the incentive of spot market prices that reflect the real scarcity conditions, it is more difficult to design market mechanisms that provide a flexible demand response. Hence, for any given cost level the energy-only market design should produce greater reliability in terms of reduced curtailments of inflexible demand.

A similar conclusion applies to a concern that an energy only market and the associated operating reserve demand curve would produce higher average costs that somehow might be avoided. The same issue arises under ICAP systems where the capacity payments appear to raise costs to customers. However, if reliability is to be maintained, some of these costs cannot be avoided. The traditional system included these costs in the rate base for the portfolio of generation owned by the utility. The costs were there, but they were less visible than explicit capacity payments or market-clearing energy prices. The costs would not be created by the ICAP requirements or operating reserve demand curve. It is the reliability requirement that gives rise to the costs. An ICAP requirement or an energy-only market would be different means to provide the payments and achieve the reliability objective.

Implementation of a demand curve for operating reserves would require attention to adapting the standards and information from the traditional model under the NERC rules. "Grid reliability is a difficult issue to discuss objectively, because few metrics describe and measure bulk system reliability consistently across the nation."[23] While this would be important, there is nothing in principle that should deter use of an energy-only market design. The market should reinforce reliability. The reliability rules and definitions may have different impacts in a market context, but the goals of reliability are not add odds with the market design.

The NERC standards already follow a structure that includes minimum operating reserve levels that should not be breached and where controlled but involuntary load curtailments should be imposed. At the minimum levels, reserves would be purchased at any price up to the price cap. However, when the price cap is below the average VOLL, this creates a conflict that produces the missing incentives and the missing money. In the

[23] Phillip G. Harris, "Relationship between Competitive Power Markets and Grid Reliability: The PJM RTO Experience," Issue Papers on Reliability and Competition, US Department of Energy and Natural Resources Canada, August 2005, pp. 4. (www.energetics.com/meetings/reliability/papers.html)

energy-only market design, a similar rule could apply regarding the minimum operating reserve levels, but the maximum price for reserves becomes the average VOLL because generation that costs more is more expensive that involuntary load reduction.

Above the minimum operating reserve levels, there is still a value for incremental reserves but the value decreases at higher levels of reserves. Explicit pricing of these incremental levels would be part of the design to eliminate the missing incentives and missing money. The operating reserve values would be set by regulators and the system operator to capture expected impacts on the system. This should include the total change in system costs across the integrated grid if everyone followed the same principles.

Although the structure of the reserve requirements might be compatible with the existing NERC standards, the level of operating reserve requirements and associated prices might turn out to be different. The NERC standards were designed for a different setting, where the value of reliability was less explicit than would be the case with a realistic operating reserve demand curve. Explicit consideration of the tradeoffs would be required for the energy-only market design, and might change the approach that NERC takes in the new era of mandatory reliability standards. With the energy-only market design, NERC's enforcement problems would be reduced because the market incentives would be compatible with the reliability requirement.

Missing Markets

The missing money problem created by limiting scarcity pricing provides an example of a missing market. There could be a market for reliability, but the regulatory constraint prevents its operation. The implicit price caps on energy and reserves present the most significant problem of this type. As a practical matter, introducing an energy-only market design with explicit energy and operating reserve demand curves may be all that is really needed to provide adequate incentives for investment in generation and other resources.

However, there are other ancillary services that are essential for successful operation of energy systems. Black start capability, regulation services, and voltage support through reactive power management are prominent examples. These services are necessary and must at least be procured by the system operator. The compensation rules for providers of these services must be adequate. However, the total expenditure may be modest relative to the energy and operating reserves under the energy-only market design.

These other ancillary services may be amenable to targeted compensation schemes that do not much affect the remainder of the energy market design. To the extent that this is not true, then it would be important to extend the analysis of the energy-only market design to include efficient pricing and incentives for these additional services. For instance, it would be possible to consider spot-pricing and forward contracting for reactive support.

Market Power

A primary concern that drove the public policy decisions towards administrative measures like price caps was the possibility of market participants possessing and exercising market power. The immediate effect of market power was cast as high prices that could not be justified by input costs. It seemed logical that the most direct route to controlling high prices would be by imposing limits on prices. This in turn created an array of other measures such as out-of-market purchases and reliability must run (RMR) contracts. And the low prices created the missing-money problem with the attendant call for resource adequacy programs.

The concern with market power would remain in an energy-only market. With no limit on energy and operating reserve prices other than the average VOLL, there would be even greater fear about potential incentives to exercise market power. The exercise of market power would violate the assumption of competitive behavior that underpins the efficiency of energy-only pricing.

The ability of generators to enter the market with new capacity supported by voluntary contracts with consumers should make the long-term energy market workably competitive. Without artificial barriers to entry, no special policy would be required to address market power in forward contracting with a sufficiently long horizon that allows for entry.

The problem would then be in the short-term spot market, especially in the presence of transmission congestion that created load pockets where generators might have substantial market power and would be able to raise prices above competitive levels. This is a large topic with many details, but the essence of the relevant points for the energy-only market design is straightforward. The market design could include administrative intervention when and where there was a serious possibility of an exercise of (local) market power through physical or economic withholding. However, the interventions would be structured to emulate the results of competition to the greatest degree possible. These interventions would be in the form of offer caps and offer requirements for generators, with appropriate exemptions for all generators who are not in a position to exercise market power or who enter a market with new facilities.

Deciding on the level of the appropriate offer caps would be contentious, but the focus would be on preventing withholding and not on keeping prices low. With the full capacity of a mitigated plant in use, the market-clearing price would be determined by the opportunity costs reflected in the demand curves and seldom by the offer cap *per se*. Setting offer caps is even more contentious in a price capped market where the effect may be to reduce supply. Furthermore, the energy-only design does not necessarily increase any incentive to exercise market power. For the same demand response, a higher price increases the incentive to produce above any given level of output. Under these conditions, when the supplier hits its capacity constraint there is no incentive to exercise market power. To the extent that the energy-only market design increases the total energy and operating reserve demand response, the design would help mitigate market power.[24]

These types of market power interventions are familiar in the organized markets under ISOs/RTOs. The principal difference with the energy-only market design would not be in the form of the market power intervention. Rather, it would be in the treatment

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[24] The common assertion that scarcity conditions increase market power depends more on an assumed movement to a nearly vertical residual demand curve than on the absolute level of price.

of scarcity pricing after mitigation to address market power. In particular, the operating reserve demand curve would allow for scarcity prices that could be very high, but would not arise from the exercise of market power. Even with offer caps in place, high demand and limited available generation capacity would create a shortage of reserves and higher prices for both energy and reserves. Hence, there would be no formal cap on prices, only limitations on economic and physical withholding for generators with market power. Market power mitigation would be targeted at the exercise of market power, not at high prices. Prices would be high during scarcity conditions and there would be no missing money.

Inadequate Contracting

If there were an adequate level of forward contracting, the contracts would reflect the expected prices going forward but customers would face relatively little exposure to the volatility of prices in spot markets. If regulators were confident voluntary contracting would suffice, the energy-only market with its voluntary forward contracts would suffice.

A principal concern of regulators could be that left to their own devices market participants might not select an appropriate level of contracting. In effect, this would be a consequence of a violation of the assumption of low transaction costs. There could be barriers to entry into contracting, particularly for small customers. Without sufficient hedges supplied through forward contracts the loads would be too exposed to volatile spot prices and this, in turn, would create inevitable pressures for regulators to intervene when scarcity appeared. This intervention would be a political challenge for regulators and would create associated regulatory uncertainty that would undermine investment.

To the extent that forward contracts would be needed by generators to maintain existing facilities or arrange the financing for new investment, insufficient demand for forward contracts could work against the intended incentives for market based resource investments. Hence, inadequate demand for forward contracts could translate into a resource adequacy problem relative to the level of investment that would occur if the transaction costs could be eliminated.

A concern with inadequate forward contracting might arise from an expectation of market failure with many small customers who are unable or unwilling to enter into forward contracts. The group illustrated above in Figure 3 as the inflexible load might have little incentive to contract. The price to the inflexible load might be fixed and probability of curtailment ignored. The load serving entities providing the inflexible load's power at fixed prices may have some incentive to contract forward, but this would depend on the regulatory design at the retail level even though the effects would be felt in the wholesale market.

Without elaborating every case, there are instances when regulators would be inclined to require forward contracting on behalf of some or all customers. In the markets where there is a missing money problem, this contracting directive moves almost immediately to contracting for installed capacity in the ICAP mode. However, in an energy-only market without a missing money problem there would be other ways to approach mandatory contracting. If the problem is forward contracting and not missing money, then the regulatory approach to forward contracting could focus on the objective and be less prescriptive about the means to achieve the objective.

Mandatory Load Hedge Contracting

The main targets for regulatory intervention would be the problems of market power and inadequate contracting. If market power could be contained with sufficient mitigation in the spot market, there would be no concern with the possibility of withholding, and the incentives of the energy-only market would provide a powerful force to make plant available when most needed. This need for mitigation is not unique to the energy-only design, and well-designed mitigation should address the market power problem.

If somehow adequate contracting could be arranged, then there would be protection for loads that would be hedged against high prices and suppliers that would avoid exposure to volatility. The challenge arises in specifying the requirement for and design of forward hedging contracts.

An "energy-only" market design could accommodate a mandatory load hedge (MLH) requirement. This would be a regulatory intervention to address the concern that there would be inadequate forward contracting. The details of MLH requirements would be important, but the critical issues introduced by an energy-only market approach would be relatively limited. The comparison with an ICAP design helps identify why removing the missing money problem would simplify the policy intervention.

ICAP and MLH

An ICAP requirement includes forward contracts with specific generators for installed capacity, sometimes with an explicit or implicit option on the energy that could be produced from the designated plant. Among the concerns with ICAP programs have been that the forward requirement horizons are not long enough to support investment, and not specific enough to support the right investments. This produces pressure to extend the horizons and specificity as to type and location.[25] Similar challenges would face any forward contracting requirement, but if the objective of MLH is framed relative to the energy-only market design, there would be important differences with the ICAP approach.

For both ICAP and MLH approaches, an initial step in specifying the requirement would be to identify the targeted load and the intended duration of the forward contracts. For the intended forward contracts, the procedure would determine the forecast load level, locations, and horizon. Although this would not be an easy task, assume that the profile of loads has been identified for each location. Under an ICAP program, this is the beginning of the process. To move load levels at specific locations to installed capacity at other locations, the load forecast must be converted into a description of the mix of transmission and generation capacity that would be required in order to meet this load requirement. The ICAP program may include specifications for demand-side alternatives with their own locational and operating characteristics. For a forecast many years ahead, this translation from demand to supply would be a complicated process with many uncertainties.

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[25] John Chandley, "ICAP Reform Proposals in New England and PJM," LECG, Report to the California ISO, September 2005.

Under an MLH approach, however, the load forecast could be enough. There would not be a requirement to convert the forecast into a prescription for production capacity by location. The system operator might be in the best position to describe correlated generator outage risk, transmission outages, weather volatility that would determine expected prices in the energy-only market. These studies could support analysis by investors deciding on where and how much generating or other capacity to build given the resulting expectation of prices. But the assumption of the energy-only market design would be to rely on the investment decisions by the market participants even when these may differ from the choices of the regulators or system operators.

For simplicity in making the distinction with ICAP, assume the regulator requires customers to arrange for energy forward contracts that met the same forecast load used to drive an ICAP requirement. The MLH contracts could be arranged through either direct negotiations or through a formal auction process. The critical distinction relative to the ICAP approach is that these MLH forward contracts would be based on prices and delivery at the load location. In effect, these would be equivalent to financial "contracts for differences" relative to the real-time locational price at the load point. To support these contracts the supplier could arrange bilateral contracts to deliver the energy to the load at the load location, or the supplier would settle for imbalances at the locational price.[26]

Unlike with the ICAP programs, under the MLH there would be no need for the regulator or the load serving entity operating on behalf of the customer to arrange for transmission delivery or link the contract to any particular generating facility. These decisions would all be handled by the market participants who agree to be the suppliers under the contracts. The costs and risks of providing the MLH hedges would fall on the supplier and be reflected in the forward contract price. However, competition among

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[26] Proposals to use financial contracts in resource adequacy programs are not new. For example, see Harry Singh, "Call Options for Energy: A Market Based Alternative to ICAP and Energy Price Caps," PG&E National Energy Group, October 16, 2000. However, most discussions of resource adequacy proposals employing forward contracts explicitly reject a strictly financial interpretation because the absence of efficient, energy-only pricing precludes the contracts from providing the right incentives for investment or operations. This missing-money problem dictates the need for the physical connection with specific resources that spawns the administrative complexity of ICAP programs. For these quasi-financial contract designs, see Miles Bidwell, "Reliability Options," Electricity Journal, Vol. 18, Issue 5, June 2005, pp. 11-25. Hung-Po Chao and Robert Wilson, "Resource Adequacy and Market Power Mitigation via Option Contracts," Electric Power Research Institute, Draft, March 18, 2004. Shmuel Oren, "Capacity Payments and Supply Adequacy in Competitive Markets," VII Symposium of Specialists in Electric Operational Systems Planning," Basil, May 2000. Shmuel Oren, "Ensuring Generation Adequacy in Competitive Electricity Markets," University of California at Berkeley, April 2004. Shmuel Oren, "Capacity Mechanisms for Generation Adequacy Insurance," CPUC-CEOB-CAISO Installed Capacity Conference, San Francisco, California, October 4-5, 2004. Roy J. Shanker, "Comments on Standard Market Design: Resource Adequacy Requirement," Federal Energy Regulatory Commission, Docket RM01-12-000, January 10, 2003. Carlos Vázquez, Michel Rivier, and Ignacio J. Pérez-Arriaga, "A Market Approach to Long-Term Security of Supply," IEEE Transactions on Power Systems, Vol. 17, No. 2, May 2002. Carlos Vázquez, Carlos Battle, Michel Rivier, and Ignacio J. Pérez-Arriaga, "Security of Supply in the Dutch Electricity Market: the Tole of Reliability Options," Report IIT-03-084IC, Comillas, Universidad Pontifica, Madrid, Draft Version 3.0, Madrid, December 15, 2003.

suppliers should drive innovation and efficiency to make the aggregate forward arrangements capture the expected benefits of the market.

Furthermore, compliance tracking under the MLH contracts would follow automatically in the energy-only market settlements of imbalances. There would be no need for the system operator or anyone else to monitor the generators or ensure the availability or deliverability of any particular generator's capacity. The market itself would provide strong incentives for the suppliers to make these arrangements in an efficient and least cost manner.

The myriad forecasting and monitoring requirements of the ICAP approach, which tend to recreate the problems of integrated resource planning, would be replaced by financial MLH contracts defined at the customer's location. A focus on financial contracts emphasizes the need for enforcement of the financial obligations. The enforcement provisions would be addressed by credit requirements that for the most part would also be present in ICAP markets. In this regard, the complexity of "physical" contracts in ICAP markets does not remove the need for enforcement of financial obligations. The typical ICAP design includes penalties for performance failure, and in the end the ICAP approach carries with it much of the baggage of the financial contract without the simplicity.

In the absence of transparent scarcity pricing of the type found in an energy-only market, a major problem for ICAP markets is to ensure compliance during periods of stress, and to make sure the requirement is broad enough and enforceable so that there is no leaning on the system. If generators could turn to a capped energy price during periods of stress, there would be strong incentives to withdraw from the ICAP obligations and pay the low damages at the capped price. Furthermore, parties outside the formal program would attempt to purchase from the capped spot market during periods of stress. It is a major challenge in ICAP markets to devise sufficient penalties, export controls, delivery obligations and enforcement mechanisms to ensure that the intended generation capacity, transmission deliverability or demand response is really available during periods of aggregate scarcity when real opportunity costs exceed the price cap. By contrast, the MLH requirement could be targeted to a part of the load, and regulators would not be faced with the problem of dealing with market participants outside their jurisdiction or outside the intended target of the program. In other words, the MLH requirement could focus in particular customer classes (e.g., residential and not industrial) and regions (e.g., inside the state and subject to state regulation).

The gold standard for ICAP programs is a set of penalties and enforcement rules that attempt to emulate the incentives of the energy-only market.[27] Of course, by construction the energy-only market creates these incentives naturally as part of its inherent design. There would be no need to have special monitoring and enforcement for generators during periods of scarcity because in the energy-only market this is precisely

[27] For example, the LICAP proposal of ISONE attempted to emulate as much as possible the incentives of an energy-only market through the design of monitoring and performance incentives. Steven Stoft, Testimony on Behalf of ISO New England on Locational Installed Capacity Market Proposal, Submitted to Federal Energy Regulatory Commission, Docket Number ER03-563-030, Direct August 31, 2004, Supplemental November 4, 2004, Rebuttal February 10, 2005.

when (very) high prices provide (very) strong incentives to perform. There would be no need for export limitations because the export loads not covered by the MLH obligation would be paying the real opportunity cost of their demand. Likewise there would be no concern with loads not covered by the MLH requirement leaning on the system because there would be no where to lean, only to stand straight and pay the full opportunity cost in the energy-only market when scarcity conditions arose. The MLH approach would provide the hedges through contracts that apply only to the parties that have contracted.

This structure would be consistent with retail access systems like the Basic Generation Service (BGS) in New Jersey.[28] The BGS involves an auction for forward procurement of energy delivered to the load. There is no specification in the contracts about how or where the supplier obtains the power or hedges its obligations. This is left to the supplier's activities in the market and the supplier's risks are internalized in the offers it makes in the auction. The rolling horizon is three years for the smallest customers and one year for larger commercial customers, with the alternative to opt out of the protection. The largest commercial and industrial customers are not included except for uplift and ICAP payments. In the context of an energy-only market design, where there would be no ICAP payments, it would be natural to ask if anything in addition to the BGS program would be required.

This outline of the relative simplicity of an MLH approach in an energy-only framework follows from its targeting of protections. In a price-capped energy market, the capped prices apply in theory to all spot transactions. In order to achieve the benefits of the forward ICAP contracts and associated investment, regulators would face the broad choice between either contracting enough so that spot prices naturally stay below the price cap for the free riders or restricting access to the capped prices through exclusionary rules that would apply during periods of scarcity. The free riders would create very high costs for those bearing the burden of forward contracting. The exclusionary rules would exacerbate the complexity and incentive problems that undermine the very purposes of the market.

By contrast, the energy-only market would not provide hedges through capped spot prices that would apply to everyone. Hence, forward contracting requirements could be limited to a targeted group. There would not be the great concern with free riders. Reaping the benefits of the forward contracts would not require exclusionary rules.

The focus on financial contracts provides great flexibility for suppliers to craft generation, transmission and demand efficiency packages to support their commitments under the MLH contract. There need be no rules to overcome missing incentives or decide on the tradeoffs between supply and demand alternatives.

In short, an MLH requirement would be an intervention by regulators to address a concern that, despite the strong incentives of the energy-only market, loads would not have sufficient interest or incentive to arrange the long-term hedges that would eventually prove necessary. But the intervention would be tailored to fit the intention of using

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[28] For a description of the New Jersey forward contracting requirement, see http://www.bpu.state.nj.us/home/bgs.shtml

market pricing to drive investment decisions. The required contracts would be financial instruments without explicit connection to any particular resources.

MLH and Other Contracts

Energy-only market pricing would be essential in relying on these relatively simple MLH instruments. Absent credible scarcity pricing of the energy-only market, any MLH requirement would confront the same perverse conditions that would compromise incentives and generator performance precisely when needed the most, during times of scarcity. An energy-only market approach could come as part of a package, with some form of MLH contracts to provide the needed hedges and the forward contracts underpinning investment in new generation (and transmission) capacity.

The generic outline of an MLH approach leaves open many details about the particulars of contract design. The essential features would be an (i) energy-only market design, (ii) specification of the obligation in financial rather than physical terms, and (iii) linking the financial terms to the prices at the load location. Within this framework there could be a variety of contract requirements that would satisfy the limited objectives of hedging sufficiently to provide the protection sought by regulators and to support the intended investment. The MLH approach would not face the additional demands of assuring operational performance or mitigating market power. These would be handled by the incentives and mitigation rules in the spot market, respectively.

The MLH form of financial contract would have much in common with the familiar "portfolio" contracts with liquidated damages (LD) found in electricity markets. The LD contracts do not identify particular resources, and the obligation is to deliver the energy from somewhere or pay the liquidated damages. The damages are often determined as the spot-market prices. In the context of a spot market, the LD contracts are financial instruments, and in a price-capped market the damages are capped. Hence, a principal complication under the price-capped energy markets is that the liquidated damages are too low, and the supplier has an incentive to lean on the spot market and pay the capped spot price during times of scarcity. As a result, the price hedging value of the LD contract remains for the customer but the contract does nothing to eliminate the missing money or the risk of involuntary curtailment. With only the obligation to deliver the energy or pay the low penalty, the equilibrium price for LD contracts would not substitute for the missing money in payments to generators. The money would still be missing from the price-capped energy market and would not be provided through the LD contract. In a price-capped market, LD contracts would be part of the problem.

By contrast, under the energy-only market approach these LD contracts might well be compatible and workable hedging instruments to substitute for some or all of the MLH requirements. To the extent that the LD requirement specifies the payment obligation as it appears in the market, movement to an energy-only market would increase the *de facto* penalty payments in the LD contracts. If these payments were also keyed to the locational price of the load, then the LD contracts could be fully included in meeting the MLH requirement. In an energy-only market, LD contracts could be part of the solution.

Under the energy-only framework, the function of the MLH requirement is more limited and the scope of the contracts more flexible than for the capacity contracts in a comparable ICAP design. Under the energy-only market design, there is no missing money and forward contracts would not carry the burden of providing additional payments above the forward price of energy. Under the energy-only market design the focus of market power mitigation would be on the spot market and not be imposed as a design constraint for the forward contracts. Under the energy-only market design spot prices would provide the incentives for generator availability during periods of scarcity and would not require performance features on the contracts.

The test of the adequacy of the MLH requirement would be in the regulator's judgment that the contracts provided sufficient hedging on average and were of long enough duration to support investment in generation and other resources. For example, it might suffice to specify the MLH requirement in terms of peak and off-peak energy blocks that follow the common pattern of bilateral arrangements. The total energy over the month for peak periods would be set, with a separate requirement for off-peak periods. The load would have the discretion as to when to exercise the contract within the period. Suppliers might contract to provide the hedge for some or all the energy and for some or all the period. This flexibility would avoid the need to specify in advance exactly which hours would apply for availability of particular quantities, avoiding some of the complications of the ICAP programs.

In addition, regulators may wish to leave some customers with a certain amount of discretion while ensuring that there is a minimal level of hedging. Hence, the MLH requirement might be specified as a call option at a high price for the contracted energy over the period. Hedging contracts with lower strike prices would suffice to meet the requirement. Further, the MLH specification could have different requirements for different groups. For example, commercial customers might be required to arrange at least the call options at a high price, while regulators might require smaller residential customers to have full requirements energy contracts at a fixed price. The challenge would be to devise a set of acceptable MLH requirements that did not require extensive review in substituting alternative contracts to meet the requirement.

The New Jersey BGS system employs flexibility in both duration and application to different customer groups. The rolling horizon for the residential load means that one-third of the forecast load is contracted anew three years in advance. Large customers have no forward obligation and can seek their own hedging arrangements or rely in part or all on the spot market.

An alternative type of flexibility might be to formulate the MLH contracts as synthetic tolling arrangements. In effect, the contract would set a price for delivery of electric energy to the load and a price for delivery of a mix of input fuels to the supplier at a standardized location. This would provide the load with a long term hedge for the non-fuel costs ("capacity") but exclude the hedge for fuel costs. This would allow for a separate decision by the load to hedge the fuel costs, perhaps closer to the time of delivery. The suppliers would avoid taking on the complete long-term fuel price risk. This might be a more attractive allocation of risk for both parties.

Since the economic incentives for investment and for operations flow from the energy-only market design and transparent scarcity pricing, the direct purpose of MLH contracts would be hedging and need not address the operations problems under the ICAP approach. There would be few limits on the flexibility of MLH requirements. The details would address the matters of duration, amount, strike price, credit requirements, and substitution rules. But as long as the requirements were specified as financial contracts relative to the load location and real-time price, the contracts would be largely independent of the remainder of the market design and operation. The contracts would impose minimal requirements on the system operator.

Transition

The sketch of an "energy-only" market design sets a destination but does not define the path. It is common in discussions of ICAP proposals to accept this destination as a goal but not consider how to get there, partly because the goal is not adequately defined. With a common understanding of the objective, it would be easier to make choices along the way.

The transition would be important and it would depend in part on the starting point. If there is no existing ICAP program and no imminent capacity shortage, the focus would be on implementing the critical reforms of the spot market design to include transparent scarcity pricing. Similarly, if there is no load hedging program in place, then this would be a focus of a regulatory decision to either accept reliance on voluntary forward contracting as politically sustainable or turn attention to mandatory load hedging for some of the customer classes.

In regions with ICAP reforms underway, and real fears of immediate capacity shortages, the attractions of an energy-only market may require a period of confidence building. However, there appears to be nothing that dictates that an improved spot market design is mutually exclusive of an ICAP approach. The absence of transparent scarcity pricing makes an ICAP program necessary and more difficult to implement. But transparent scarcity pricing for energy and operating reserves would simplify many of the monitoring and performance problems that come with an ICAP approach.

A goal of moving to an energy only market design should influence the design of any ICAP program. The better the scarcity pricing the less burden there would be on designing performance standards, the easier it would be to develop demand alternatives, and the easier it would be to set criteria for phase out of the ICAP system. For example, recent ICAP reform proposals such as the Reliability Pricing Model in PJM set the demand for installed capacity with the price determined net of an estimate of the revenues that should be earned in the spot market.[29] With transparent scarcity pricing and an appropriate operating reserve demand curve (plus a compatible installed reserve planning target and a few other simplifying assumptions) this net price of capacity would be zero and the role of the ICAP requirement would fade, or at least be substantially reduced.

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[29] John Chandley, "ICAP Reform Proposals in New England and PJM," LECG, Report to the California ISO, September 2005.

A common step would be to address directly the interaction between reliability standards and market design. The Energy Policy Act of 2005 requires FERC to propose rules to establish a new Electric Reliability Organization (ERO), set mandatory reliability standards and provide for enforcement.[30] These new standards could be compatible with the principles of the operating reserve demand curve, or not. Everyone would benefit if the standards and rules were written in explicit recognition of the charge to have markets reinforce reliability.[31] Poorly designed markets and poorly designed reliability standards would make everything harder.

An explicit consideration of the destination and the transition path would be important for mitigating regulatory risk. Market observers regularly identify uncertainty about regulatory rules and pricing as a principal obstacle to investment. Hence, despite any promises that the rules will be stable, an unsustainable system will be seen for what it is and the confidence required to support investment will be impossible to mandate. The basic elements of a successful market design are not a mystery, and experience shows that deferring attention to market design increases the likelihood and cost of the failures, requiring ever more interventions and changes of the rules. It is reasonable to conclude that moving quickly to a successful market design is a necessary condition for mitigating regulatory risk.

Conclusion

The missing money problem reflects a view that market design imperfections suppress electricity prices in spot markets. This produces inadequate incentives to invest in infrastructure resources such as generation capacity and its substitutes. A common policy response is to mandate purchases of installed capacity as a resource adequacy requirement. When this proves inadequate, more prescriptive reforms arise to compensate for the missing incentives in the market. An alternative approach would be to address the imperfections in the market design, provide the missing incentives, and eliminate the missing money. The resulting "energy only" market would not remove the need for regulatory interventions, but it would substantially change the character of those interventions. A sketch of such a market design illustrates how to address the market imperfections without overturning the market.

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[30] Federal Energy Regulatory Commission, "Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards," 18 CFR Part 38, Docket No. RM05-30-000, September 1, 2005.

[31] U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004, p. 140.

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Endnotes

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