REGULATION AND ELECTRICITY MARKETS

William W. Hogan

Mossavar-Rahmani Center for Business and Government
John F. Kennedy School of Government
Harvard University
Cambridge, Massachusetts 02138

Western Power Trading Forum

New York, NY

April 16, 2009

The case of electricity restructuring presents examples of fundamental problems that challenge regulation of markets.

- **Marriage of Engineering and Economics.**
  - **Loop Flow.**
  - **Reliability Requirements.**
  - **Incentives and Equilibrium.**

- **Devilish Details.**
  - **Market Power Mitigation.**
  - **Coordination for Competition.**

- **Jurisdictional Disputes.**
  - **US State vs. Federal Regulators.**
  - **European Subsidiarity Principle.**

The short term financial crisis and long term energy policy provide a context with a rapidly changing view of the role of government.

- **Financial Crisis Presents Conflicting Diagnoses**

  "Deregulation, or the failure of regulators to keep up with fast-moving markets, can become unbelievably costly, as we have seen."[1]

- **Going Green Implies a Major Transformation of the Electricity Sector**

  Climate change policy and the expanded focus on renewables present a fast moving array of subsidies, regulations and mandates.

- **Electricity Restructuring is not Electricity Deregulation**

  Electricity markets with Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), the North American Electric Reliability Corporation (NERC), State Public Utility Commissions (PUCs), Public Power Authorities, and the Federal Energy Regulatory Commission (FERC) are highly regulated entities. But "failure of regulators to keep up with fast-moving markets, can become unbelievably costly, as we have seen."

The challenge of "keeping up" emphasizes the dynamic nature of the problems and the importance of understanding the fundamentals of first principles.

---

1 Francis Fukuyama, "The Fall of America, Inc.," Newsweek, October 13, 2008, p. 32.

The Federal Energy Regulatory Commission has responsibility for regulating wholesale electricity markets. The stated framework emphasizes support for competition in wholesale markets as a clear and continuing national policy:

> "While competitive markets face challenges, we should acknowledge that competition in wholesale power markets is national policy. The Energy Policy Act of 2005 embraced wholesale competition as national policy for this country. It represented the third major federal law enacted in the last 25 years to embrace wholesale competition. To my mind, the question before the Commission is not whether competition is the correct national policy. That question has been asked and answered three times by Congress.
>
> If we accept the Commission has a duty to guard the consumer, and that competition is national policy, our duty is clear. It is to make existing wholesale markets more competitive. That is the heart of this review: to not only identify the challenges facing competitive wholesale markets but also identify and assess solutions."[2]

> "Competition is at heart of U.S. energy policy relating to wholesale power and gas markets."[3]

A task for regulation is to support this policy framework while developing hybrid markets and dealing with both the limits of markets and the failures of market designs.

---

2 Joseph T. Kelliher, "Statement of Chairman Joseph T. Kelliher," Federal Energy Regulatory Commission, Conference on Competition on Wholesale Power Markets AD07-7-000. February 27, 2007.

3 Joseph T. Kelliher, "Energy Competition and Regulation: The U.S. Experience," Sydney, Australia, June 26, 2008.

There is a tension in choosing regulation to address immediate market failures and to deal with the continuing challenge of improving electricity market design.

- **Little "r" regulation:**

  Design rules and policies that are the "best mixture" to support competitive wholesale electricity markets. A key requirement is to relate any proposed solution to the larger framework and to ask for alternatives that better support or are complementary to the market design. Many seemingly innocuous decisions appear isolated and sui generis, but on closer inspection are fundamentally incompatible with and undermine the larger framework.

- **Big "R" regulation:**

  Frame every problem in its own terms—inadequate demand response, insufficient infrastructure investment, or market power—and design ad hoc regulatory fixes that accumulate to undermine market incentives. This creates a slippery slope problem, where one ad hoc solution creates another problem, and regulators are driven more and more to intervene in ever more ad hoc ways.

For example, socialized costs for preferred infrastructure investment can easily reduce the incentives for other market-based investments, thereby increasing the need for regulators to select among additional appropriate investments and socialize even more costs.

The public policy debate over reshaping the electricity industry confronts major challenges in balancing public interests and reliance on markets.

The International Energy Agency (IEA) examined the international experience and produced guidance for electricity restructuring.

- "Governments must ensure a stable and competitive investment framework that sufficiently rewards adequate investments in a timely manner. …
- Governments urgently need to reduce investment risks by giving firmer and more long-term direction on climate change abatement policies. …
- Governments should pursue the benefits of competitive markets to allow for more efficient and more transparent management of investment risks. …
- Governments need to ensure that independent regulators and system operators establish transparent market rules that are clear, coherent and fair. …
- Governments must refrain from price caps and other distorting market interventions. …
- Governments must implement clearer and more efficient procedures for approval of new electricity infrastructure. …"[4]

[4] International Energy Agency, Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, Paris, 2007, pp. 15-25.

Application of the broad goals identified by the IEA would be compatible with recommendations by Paul Joskow for a new Federal Power Act.

"What provisions might a Federal Power Act of 2009 contain?

- [Federalize transmission] …
- [Mandate Regional Transmission Organizations] The key provisions of FERC Order 2000 should be put into law. This would require the creation of RTOs that manage the operation of large regional transmission networks, implement FERC's transmission access, pricing, and planning regulations, and operate voluntary wholesale markets for electric energy, ancillary services, capacity and transmission rights. There is abundant evidence (a) that RTOs are needed to support efficient competitive markets, (b) that expanding the geographic expanse of RTOs and improving the market designs for energy, ancillary services and capacity lead to efficiency improvements, (c) and that wholesale market designs built around what is generally referred to as the "standard market design," augmented by capacity obligations and capacity markets, promote economic efficiency.
- [Unbundle generation and distribution] …
- [States determine retail access] …
- [Limit generation subsidies to merchant investments] …
- [Allocate any free CO2 allowances to electricity consumers] …
- [State regulatory jurisdiction continue over distribution facilities] …" [5]

---

[5] Paul Joskow, "Challenges For Creating A Comprehensive National Electricity Policy," Technology Policy Institute Keynote Speech, Washington DC, September 26, 2008. (available at http://www.hks.harvard.edu/hepg/).

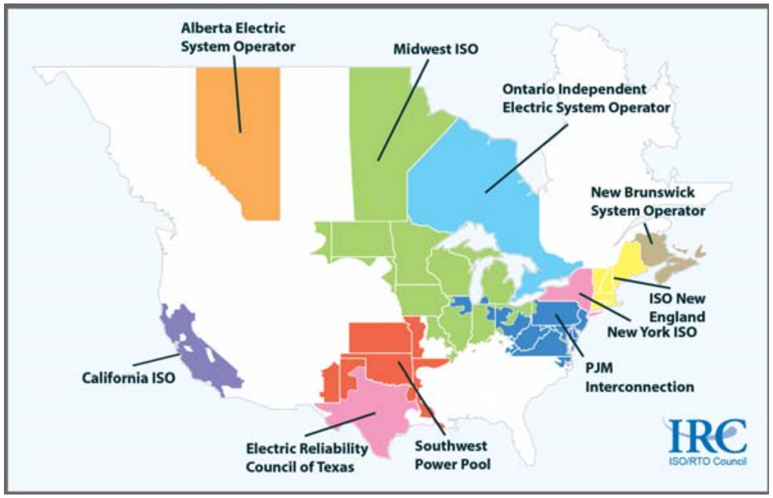
Market design in RTOs/ISOs is well advanced but still incomplete.[6]

- **Regional Markets Not Fully Deployed**
- **Reforms of Reforms**

  California MRTU (April 1, 2009) and forthcoming ERCOT Texas Nodal reforms.

- **Market Defect: Scarcity Pricing**

  Better scarcity pricing to support operations, infrastructure investment and resource adequacy.



- **Market Failure: Transmission Investment**

  - Regulatory mandates for lumpy transmission mixed with market-based investments.
  - Design principles for cost allocation to support a mixed market (i.e., beneficiary pays).

- **Market Challenge: Address Requirements for Climate Change Policy**

---

6 William W. Hogan, "Electricity Market Structure and Infrastructure," Conference on Acting in Time on Energy Policy, Harvard University, September 18-19, 2008. (available at www.whogan.com).

Scarcity pricing presents one of the important challenges for Regional Transmission Organizations (RTOs) and electricity market design. Simple in principle, but more complicated in practice, inadequate scarcity pricing is implicated in several problems associated with electricity markets.

- **Investment Incentives.** Inadequate scarcity pricing contributes to the "missing money" needed to support new generation investment. The policy response has been to create capacity markets. Better scarcity pricing would reduce the challenges of operating good capacity markets.

- **Demand Response.** Higher prices during critical periods would facilitate demand response and distributed generation when it is most needed. The practice of socializing payments for capacity investments compromises the incentives for demand response and distributed generation.

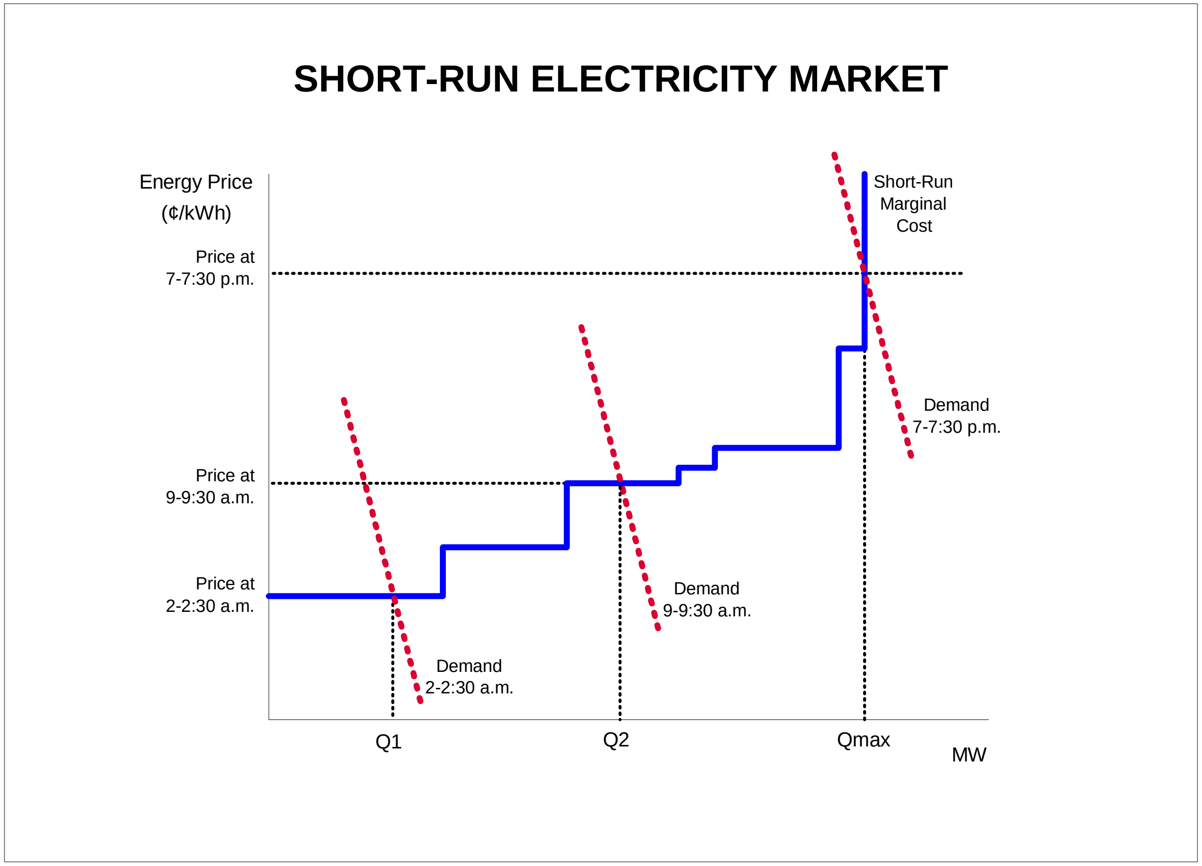
- **Renewable Energy.** Intermittent energy sources such as solar and wind present complications in providing a level playing field in pricing. Better scarcity pricing would reduce the size and importance of capacity payments and improve incentives for renewable energy.

- **Transmission Pricing.** Scarcity pricing interacts with transmission congestion. Better scarcity pricing would provide better signals for transmission investment.

Improved scarcity pricing would mitigate or substantially remove the problems in all these areas. While long-recognized, only recently has there been renewed interest in developing a better theory and practice of scarcity pricing.[7]

[7] FERC, Order 719, October 17, 2008.

Early market designs presumed a significant demand response. Absent this demand participation most markets implemented inadequate pricing rules equating prices to marginal costs even when capacity is constrained. This produces a "missing money" problem.



The theory and practice of scarcity pricing intersect important elements of electricity systems and economic dispatch.

- **Reliability.** By definition, scarcity conditions arise when the system is constrained and dispatch is modified to respect reliability constraints.
- **Dispatch.** Simultaneous optimization of energy and reserves means that scarcity in either effects prices for both.
- **Resource Adequacy.** The standards for resource adequacy and operating security are not fully integrated or compatible.

A critical connection is the treatment of operating reserves and construction of operating reserve demand curves. The basic idea of applying operating reserve demand curves is well tested and found in operation in important RTOs.

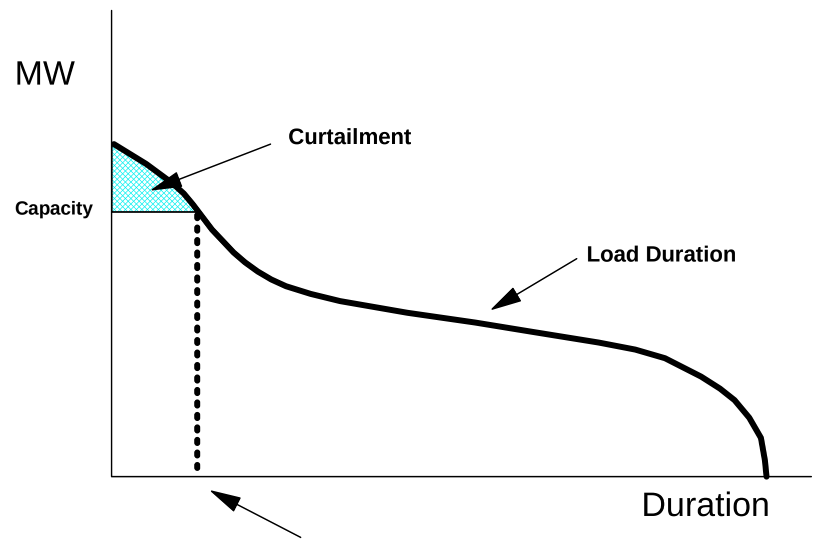
- **NYISO.** See NYISO Ancillary Service Manual, Volume 3.11, Draft, April 14, 2008, pp, 6-19 - 6-22.
- **ISONE.** FERC Electric Tariff No. 3, Market Rule I, Section III.2.7, February 6, 2006.
- **MISO.** FERC Electric Tariff, Volume No. 1, Schedule 28, January 22, 2009.

The underlying models of operating reserve demand curves differ across RTOs. One need is for a framework that develops operating reserve demand curves from first principles to provide a benchmark for the comparison of different implementations.

- **Operating Reserve Demand Curve Components.** The inputs to the operating reserve demand curve construction can differ and a more general model would help specify the result.
- **Locational Differences and Interactions.** The design of locational operating reserve demand curves presents added complications in accounting for transmission constraints.
- **Economic Dispatch.** The derivation of the locational operating demand curves has implications for the integration with economic dispatch models for simultaneous optimization of energy and reserves.

There is a simple stylized connection between reliability standards and resource economics. Defining expected load shedding duration, choosing installed capacity, or estimating value of lost load address different facets of the same problem.

A Simple Reliability Model

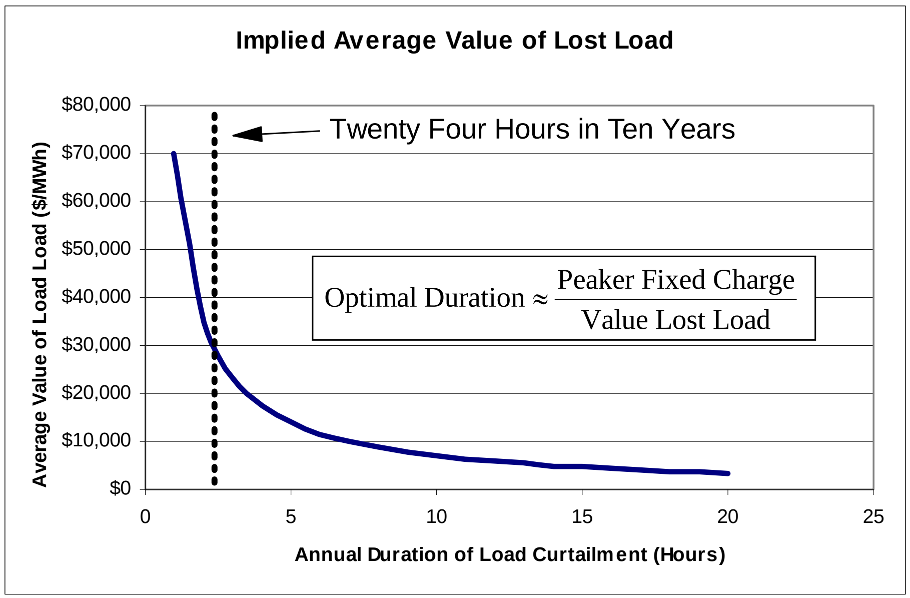


$$\text{Optimal Duration} \approx \frac{\text{Peaker Fixed Charge}}{\text{Value Lost Load}}$$

(Steven Stoft, Power System Economics, IEE Press, Wiley Interscience, 2002, p. 138)

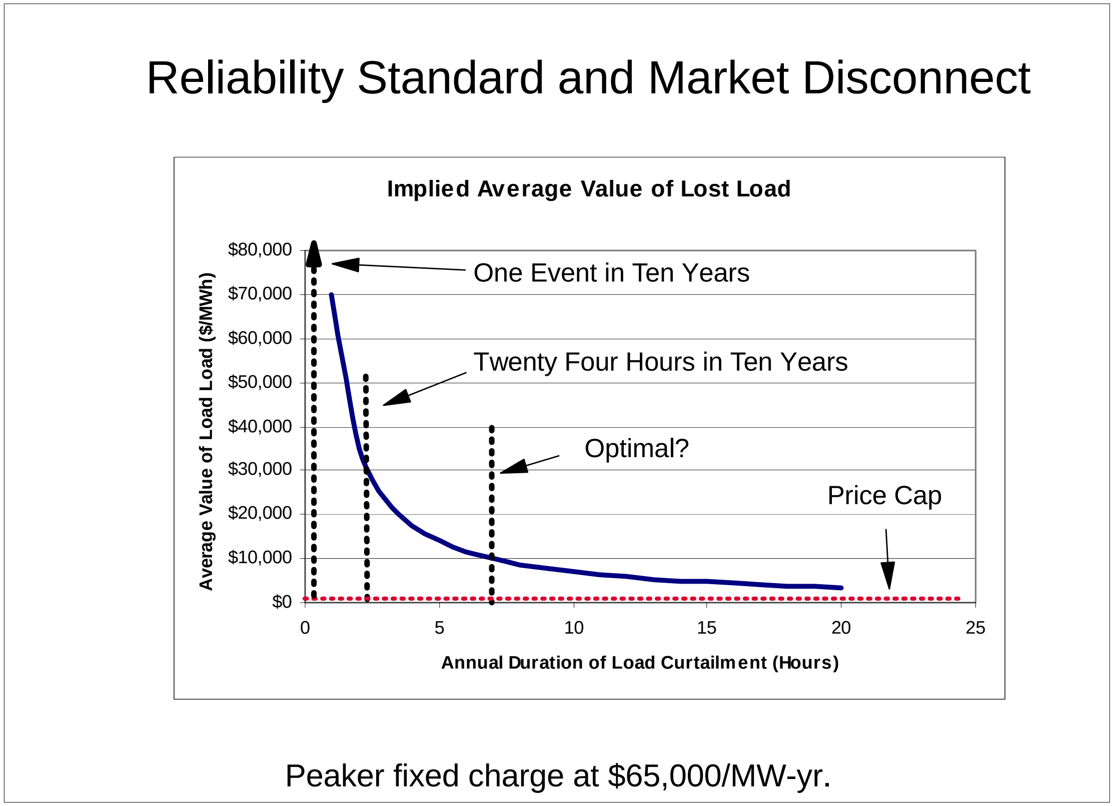
The simple connection between reliability planning standards and resource economics illustrates a major disconnect between market pricing and the implied value of lost load.

Reliability Planning Standard and Value of Lost Load



Peaker fixed charge at $65,000/MW-yr.

There is a large disconnect between long-term planning standards and market design. The installed capacity market analyses illustrate the gap between prices and implied values. The larger disconnect is between the operating reserve market design and the implied reliability standard.



Implied prices differ by orders of magnitude. $\left(\text{Price Cap} \approx \$10^3;\ \text{VOLL} \approx \$10^4;\ \text{Reliability Standard} \approx \$10^5\right)$

Ignore the network features for the first illustration. Assume all the load and generations is at a single location. Focus on the deviations form the base dispatch. Unserved energy demand is a random variable with a distribution for the probability that load exceeds available capacity.

$$Unserved\ Energy = Max\left(0, Load - Available\ Capacity\right)$$

Hence

$$\begin{aligned} Unserved\ Energy &= Max\left(0, E\left(Load\right) + \Delta\ Load - \left(Committed\ Capacity - \Delta Capacity\right)\right) \\ &= Max\left(0, \Delta\ Load + Outage + \left(E\left(Load\right) - Committed\ Capacity\right)\right) \\ &= Max\left(0, \Delta\ Load + Outage - Operating\ Reserve\right). \end{aligned}$$

This produces the familiar loss of load probability (*LOLP*) calculation, for which there is a long history of analysis and many techniques. With operating reserves (*r*),

$$LOLP = \Pr\left(\Delta\ Load + Outage \geq r\right) = \overline{F}_{LOL}\left(r\right).$$

A common characterization of a reliability constraint is that there is a limit on the *LOLP.* This imposes a constraint on the required reserves (*r*).

$$\overline{F}_{LOL}\left(r\right) \leq LOLP_{Max}.$$

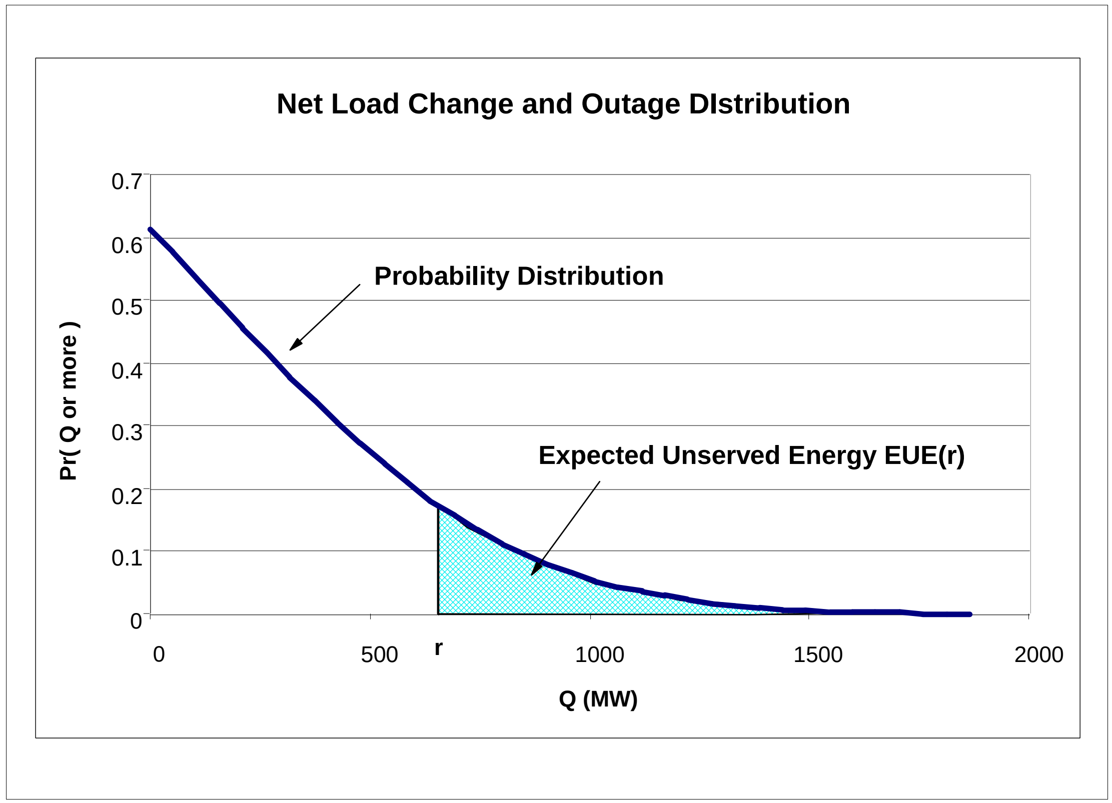
This constraint formulation implies an infinite cost for unserved energy above the constraint limit, and zero value for unserved energy that results within the constraint.

An alternative approach is to consider the expected unserved energy (*EUE*) and the Value of Lost Load (*VOLL*).

Suppose the *VOLL* per MWh is v. Then we can obtain the *EUE* and its total value (*VEUE*) as:

$$EUE(r) = \int_r^\infty \overline{F}_{LOL}(x)\,dx.$$

$$VEUE(r) = v\int_r^\infty \overline{F}_{LOL}(x)\,dx.$$



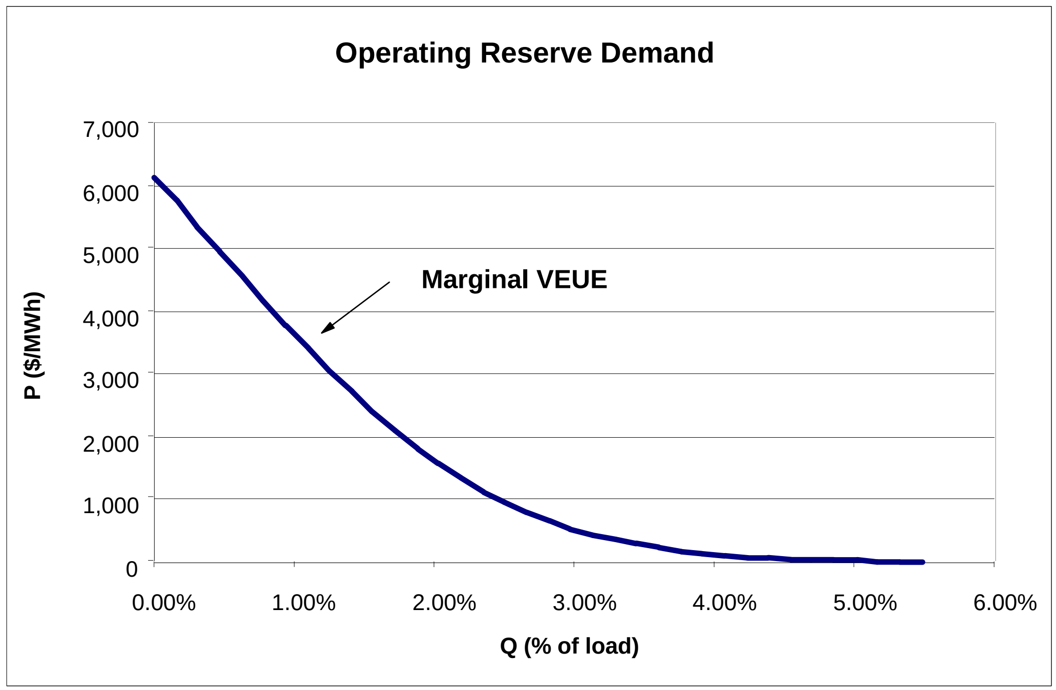
There is a chance that no outage occurs and that net load is less than expected, or $\overline{F}_{LOL}(0) < 1.$

The real changes may not be continuous, but it is common to apply continuous approximations. Total value of expected unserved energy is of same magnitude as the cost of meeting load.

Operating reserve demand is a complement to energy demand for electricity. The probabilistic demand for operating reserves reflects the cost and probability of lost load.[8]

Example Assumptions

Expected Load (MW)	34000
Std Dev %	1.50%
Expected Outage %	0.45%
Std Dev %	0.45%
Expected Total (MW)	153
Std Dev (MW)	532.46
VOLL ($/MWh)	10000



Under the simplifying assumptions, if the dispersion of the LOLP distribution is proportional to the expected load, the operating reserve demand is proportional to the expected load.

---

8 "For each cleared Operating Reserve level less than the Market-Wide Operating Reserve Requirement, the Market-Wide Operating Reserve Demand Curve price shall be equal to the product of (i) the Value of Lost Load ("VOLL") and (ii) the estimated conditional probability of a loss of load given that a single forced Resource outage of 100 MW or greater will occur at the cleared Market-Wide Operating Reserve level for which the price is being determined. … The VOLL shall be equal to $3,500 per MWh." MISO, FERC Electric Tariff, Volume No. 1, Schedule 28, January 22, 2009, Sheet 2226.

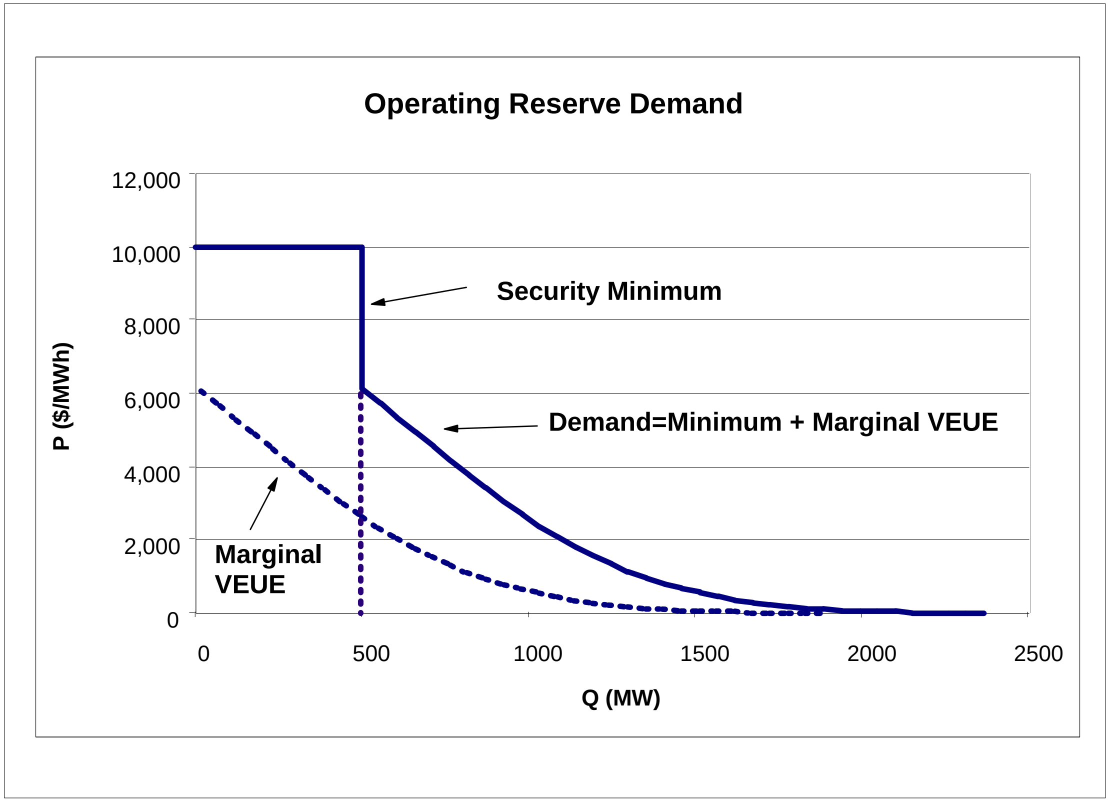
The deterministic approach to security constrained economic dispatch includes lower bounds on the required reserve to ensure that for a set of monitored contingencies (e.g., an n-1 standard) there is sufficient operating reserve to maintain the system for an emergency period.

Suppose that the maximum generation outage contingency quantity is $r_{Min}\left(d^0, g^0, u\right)$. Then we would have the constraint:

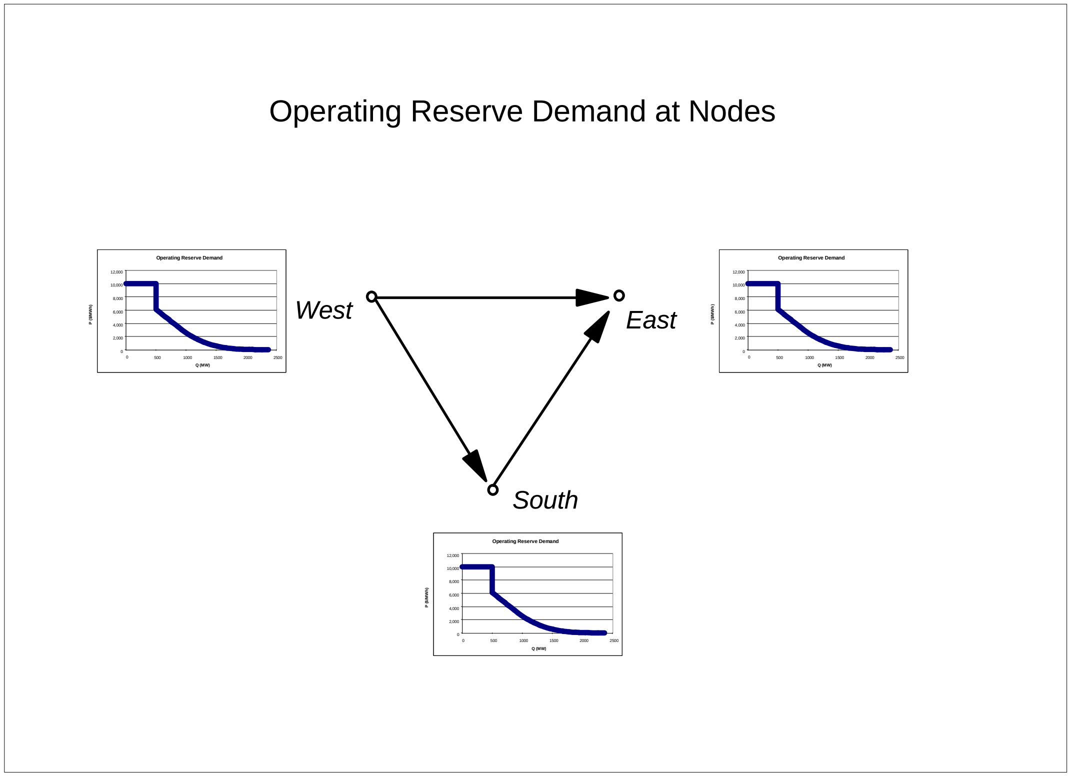
$$r \geq r_{Min}\left(d^0, g^0, u\right).$$

In effect, the contingency constraint provides a vertical demand curve that adds horizontally to the probabilistic operating reserve demand curve.

If the security minimum will always be maintained over the monitored period, the VEUE price at r=0 applies. If the outage shocks allow excursions below the security minimum during the period, the VEUE starts at the security minimum.



Conceptually we could think of the *LOLP* distribution at each location.[9] This would give rise to an operating reserve demand curve at each location.



9 Eugene G. Preston, W. Mack Grady, Martin L. Baughman, "A New Planning Model for Assessing the Effects of Transmission Capacity Constraints on the Reliability of Generation Supply for Large Nonequivalenced Electric Networks," IEEE Transactions on Power Systems, Vol. 12, No. 3, August 1997, pp. 1367-1373. J. Choi, R. Billinton, and M. Futuhi-Firuzabed, "Development of a Nodal Effective Load Model Considering Transmission System Element Unavailabilities," IEE Proceedings - Generation, Transmission and Distribution, Vol. 152, No. 1, January 2005, pp. 79-89.

A difficulty with defining a locational operating reserve demand curve is the complexity of the interactions among locations plus interactions with the transmission grid. A similar problem appears in the evaluation of planned transmission and generation investment.

- **Expected Values.** The basic formulation of the real-time economic dispatch problem is built on a particular configuration of the transmission grid and the usual application of Kirchoff's laws. The operating reserve and long-term planning problem share a focus on the expected values of outcomes across different conditions. The expected value in principle applies probabilities across many configurations and the expected value need not follow the individual dictates of Kirchoff's laws.

- **Zonal Model.** The expected value formulation rationalizes approximation in a zonal model. The zonal application across a wide range of conditions is a regular feature of RTO transmission planning and resource adequacy calculations.

  - **Zones with Closed Interfaces.** Areas with limited transmission are defined and treated as having a close interface with a capacity limit for emergency transfers from the rest of the system.

  - **Capacity Emergency Transfer Limit (CETL).** Conservative transmission standards (e.g., 1 day in 25 years) apply to simulations that determine the transfer limit.[10]

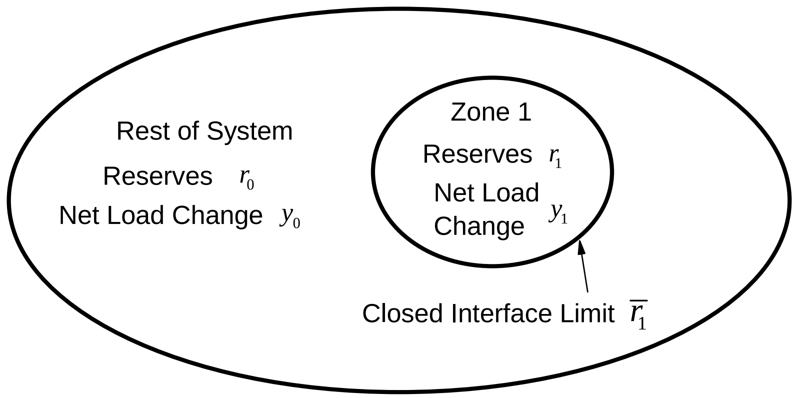
- **Interface Limits.** Although the exact CETL calculations might not be appropriate for short-term reserve management, the analogy could be applied to determine closed interface limits.

---

10 PJM , *2008 PJM Reserve Requirement Study*, October 8, 2008, Appendix H.

The task is to define a locational operating reserve model that approximates and prices the dispatch decisions made by operators. To illustrate, consider the simplest case with one constrained zone and the rest of the system. The reserves are defined separately and there is a known transfer limit for the closed interface between the constrained zone and the rest of the system.

Zonal Interface Limit on Emergency Transfers

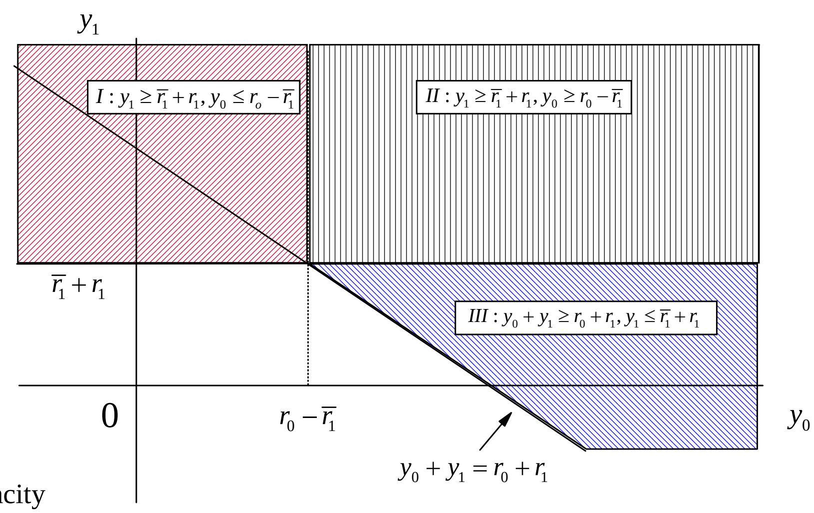


$$y_0 \sim f_0, y_1 \sim f_1, F_o\left(y_0\right) = \int_{-\infty}^{y_0} f_0\left(x_0\right) dx_0, F_1\left(y_1\right) = \int_{-\infty}^{y_1} f_1\left(x_1\right) dx_1$$

The basic emergency dispatch problem is to determine the configuration of lost load. And the expected value of the loss load defines the zonal value of expected unserved energy.

$$ZVEUE\left(r_0,\overline{r}_1,r_1\right)=E_y\left[\underset{l_i\geq 0}{Min}\quad\left\{v_0 l_0+v_1 l_1 \middle| y_0+y_1-l_0-l_1\leq r_0+r_1,\, y_1-l_1\leq \overline{r}_1+r_1\right\}\right]$$

Model for Zonal Operating Reserve and Load Loss



$\overline{r}_1 =$ Interface Reserve Capacity
$r_0 =$ Reserves Outside Zone
$r_1 =$ Reserves Inside Zone
$y_0 =$ Net Load Change Outside Zone
$y_1 =$ Net Load Change Inside Zone

$I:$ load loss $l_1, VOLL_1 = v_1$
$II:$ load loss $l_1, VOLL_1 = v_1$, load loss $l_0, VOLL_0 = v_0$
$III:$ load loss $l_0, VOLL_0 = v_0$
$v_1 \geq v_0$

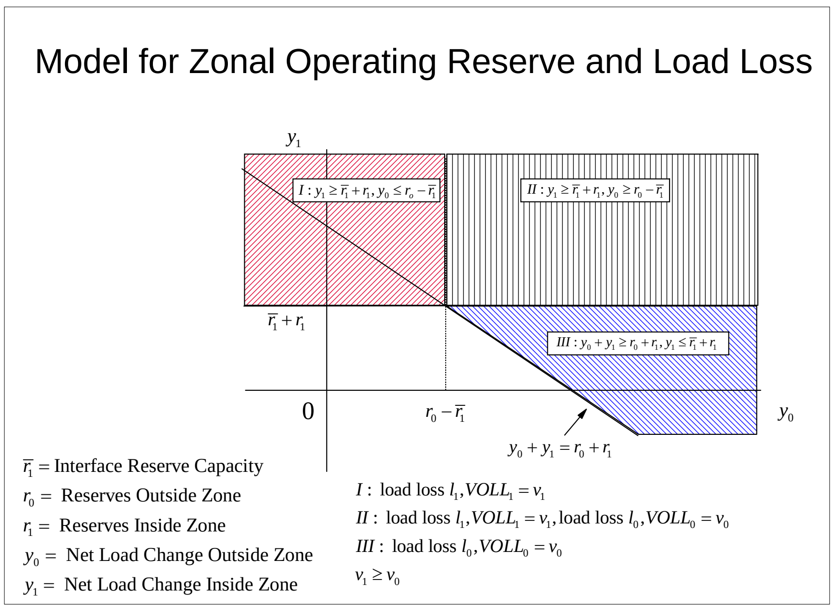
The basic emergency dispatch problem is to determine the configuration of lost load. Examination of the possible configurations of outages reveals the marginal values of the zonal value of unserved energy, which define the locational demand curves for operating reserves.

$$p_{r_1} = -\frac{\partial ZVEUE\left(r_0, \overline{r}_1, r_1\right)}{\partial r_1} = v_1 P\left(I + II\right) + v_0 P\left(III\right) = v_1 P\left(y_1 \geq \overline{r}_1 + r_1\right) + v_0 P\left(y_0 + y_1 \geq r_0 + r_1, y_1 \leq \overline{r}_1 + r_1\right)$$

$$p_{\overline{r}_1} = -\frac{\partial ZVEUE\left(r_0, \overline{r}_1, r_1\right)}{\partial \overline{r}_1} = v_1 P\left(I + II\right) - v_0 P\left(II\right) = v_1 P\left(y_1 \geq \overline{r}_1 + r_1\right) - v_0 P\left(y_0 \geq r_0 - \overline{r}_1, y_1 \geq \overline{r}_1 + r_1\right)$$

$$p_{r_0} = -\frac{\partial ZVEUE\left(r_0, \overline{r}_1, r_1\right)}{\partial r_0} = v_0 P\left(II + III\right) = v_0\left[P\left(y_0 + y_1 \geq r_0 + r_1, y_1 \leq \overline{r}_1 + r_1\right) + P\left(y_0 \geq r_0 - \overline{r}_1, y_1 \geq \overline{r}_1 + r_1\right)\right]$$

$$= v_0 P\left(y_0 + y_1 \geq r_0 + r_1, y_0 \geq r_0 - \overline{r}_1\right)$$



As explained in an appendix, these operating reserve demand curves can be reduced to probability calculations in terms of the distributions of net load changes in the constrained zone and the rest of the system.

$$p_{r_1} = v_1\left(1 - F_1\left(\overline{r}_1 + r_1\right)\right) + v_0 \int_{-\infty}^{\overline{r}_1 + r_1} \left[1 - F_0\left(r_0 + r_1 - x_1\right)\right] f_1\left(x_1\right) dx_1$$

$$p_{\overline{r}_1} = v_1\left(1 - F_1\left(\overline{r}_1 + r_1\right)\right) - v_0\left(1 - F_0\left(r_0 - \overline{r}_1\right)\right)\left(1 - F_1\left(\overline{r}_1 + r_1\right)\right)$$

$$p_{r_0} = v_0 \int_{r_0 - \overline{r}_1}^{\infty} \left[1 - F_1\left(r_0 + r_1 - x_0\right)\right] f_0\left(x_0\right) dx_0$$

The implied demand curves illustrate critical properties.

- **Interaction.** The demand curves are interdependent, but the dependence is not in the form of the nested or cascading model often assumed.
- **Convergence.** As the interface capacity increases, the implied demand curves in the constrained zone and for the rest of the system converge to the same prices.
- **Interface Demand.** In addition to the demand for operating reserves, there is an implied demand curve for the interface transfer limit.
- **No Thresholds.** The implied demand curve scarcity prices are positive at all levels. At higher reserves the prices are lower, but there is no threshold where the scarcity price falls to zero.

Using the same example as above, we separate the system into two zones with independent probability distributions. The expected total outage, standard deviations, and VOLLs are consistent with the unconstrained example above.

	ROS	Zone 1
Expected Total (MW)	107.10	45.90
Std Dev (MW)	488.99	209.57
VOLL ($/MWh)	7000	10000

Virtually any realistic distributional could be accommodated. For the sake of the illustration, continue the assumption that the individual net load distributions follow a normal approximation.

The resulting demand curves all depend on all the parameters. For a given benchmark of the values for operating reserves and the interface constraint, we can calculate the associated prices and trace out the implied demand curves when varying one dimension while holding the others constant. For the examples that follow, the benchmark reserves and interface point is:

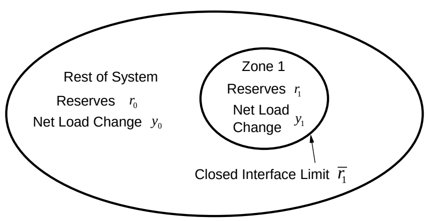
	ROS	Zone 1	Interface
Benchmark (MW)	160.65	45.90	68.85

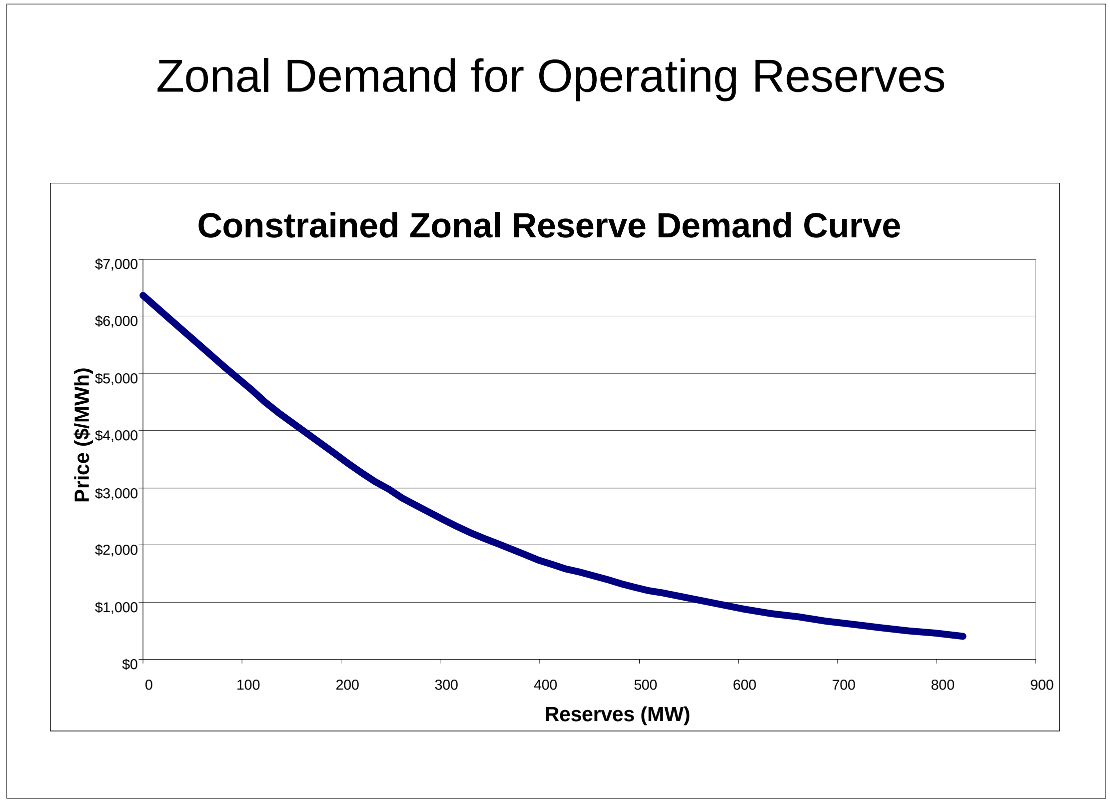
An illustrative demand curve for the constrained zone.

	ROS	Zone 1
Expected Total (MW)	107.10	45.90
Std Dev (MW)	488.99	209.57
VOLL ($/MWh)	7000	10000

	ROS	Zone 1	Interface
Benchmark (MW)	160.65	45.90	68.85

Zonal Interface Limit on Emergency Transfers



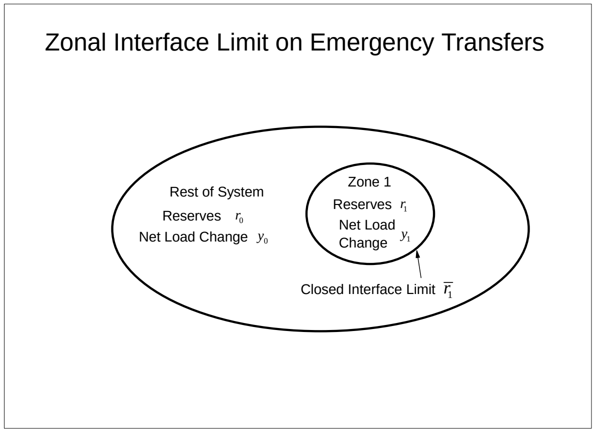


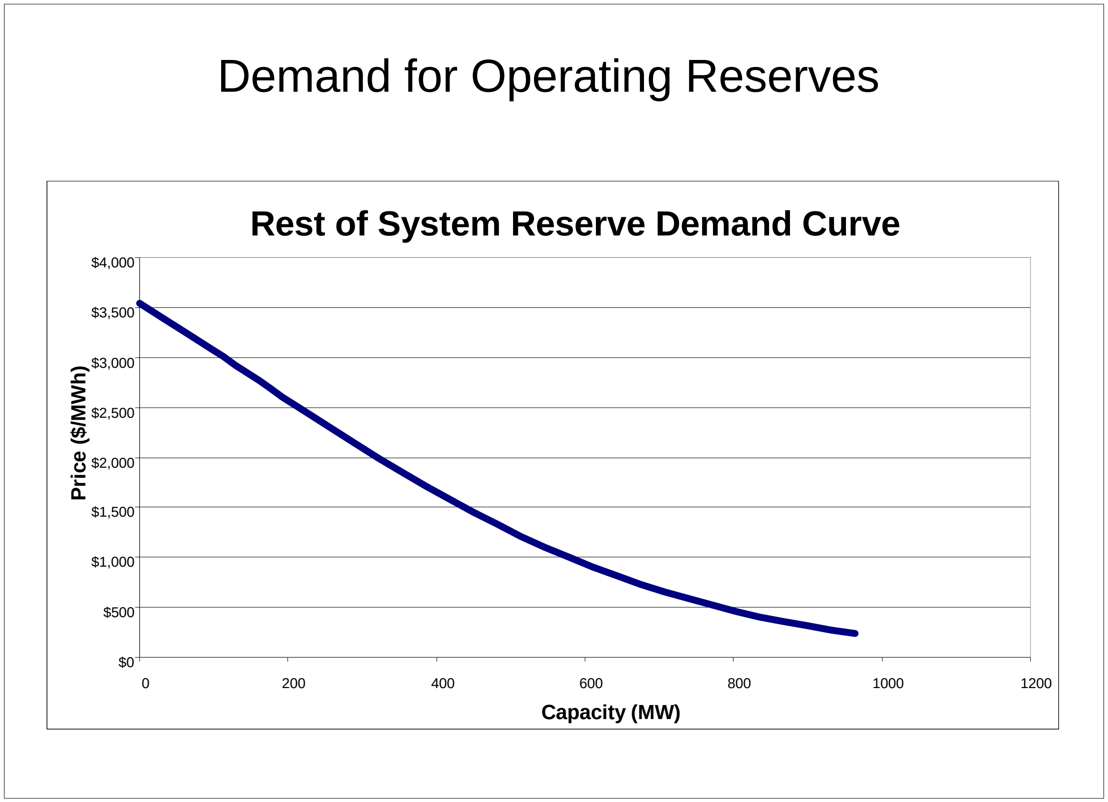
$$p_{r_1} = v_1\left(1 - F_1\left(\bar{r}_1 + r_1\right)\right) + v_0 \int_{-\infty}^{\bar{r}_1 + r_1} \left[1 - F_0\left(r_0 + r_1 - x_1\right)\right] f_1\left(x_1\right) dx_1$$

An illustrative demand curve for the rest of the system.

	ROS	Zone 1
Expected Total (MW)	107.10	45.90
Std Dev (MW)	488.99	209.57
VOLL ($/MWh)	7000	10000

	ROS	Zone 1	Interface
Benchmark (MW)	160.65	45.90	68.85





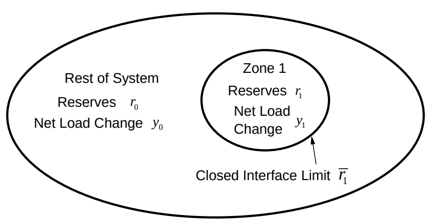
$$p_{r_0} = v_0 \int_{r_0-\overline{r}_1}^{\infty} \left[1 - F_1\left(r_0 + r_1 - x_0\right)\right] f_0\left(x_0\right) dx_0$$

An illustrative demand curve for the interface capacity.

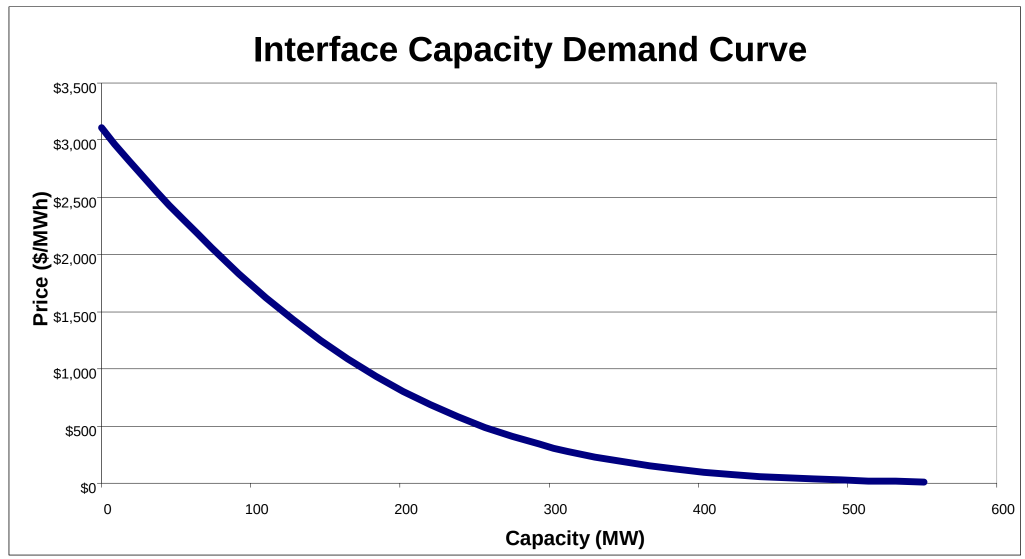
	ROS	Zone 1
Expected Total (MW)	107.10	45.90
Std Dev (MW)	488.99	209.57
VOLL ($/MWh)	7000	10000

	ROS	Zone 1	Interface
Benchmark (MW)	160.65	45.90	68.85

Zonal Interface Limit on Emergency Transfers

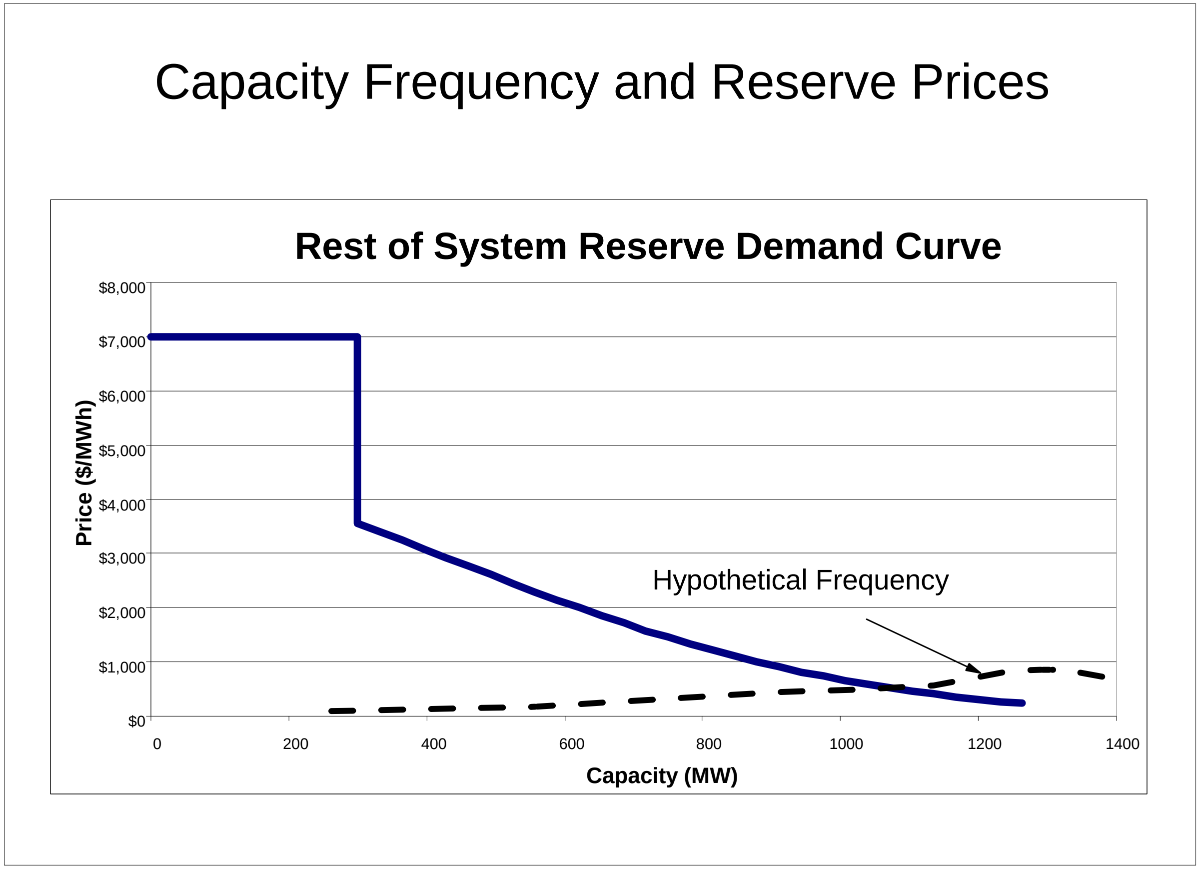


Zonal Demand for Transfer Limit

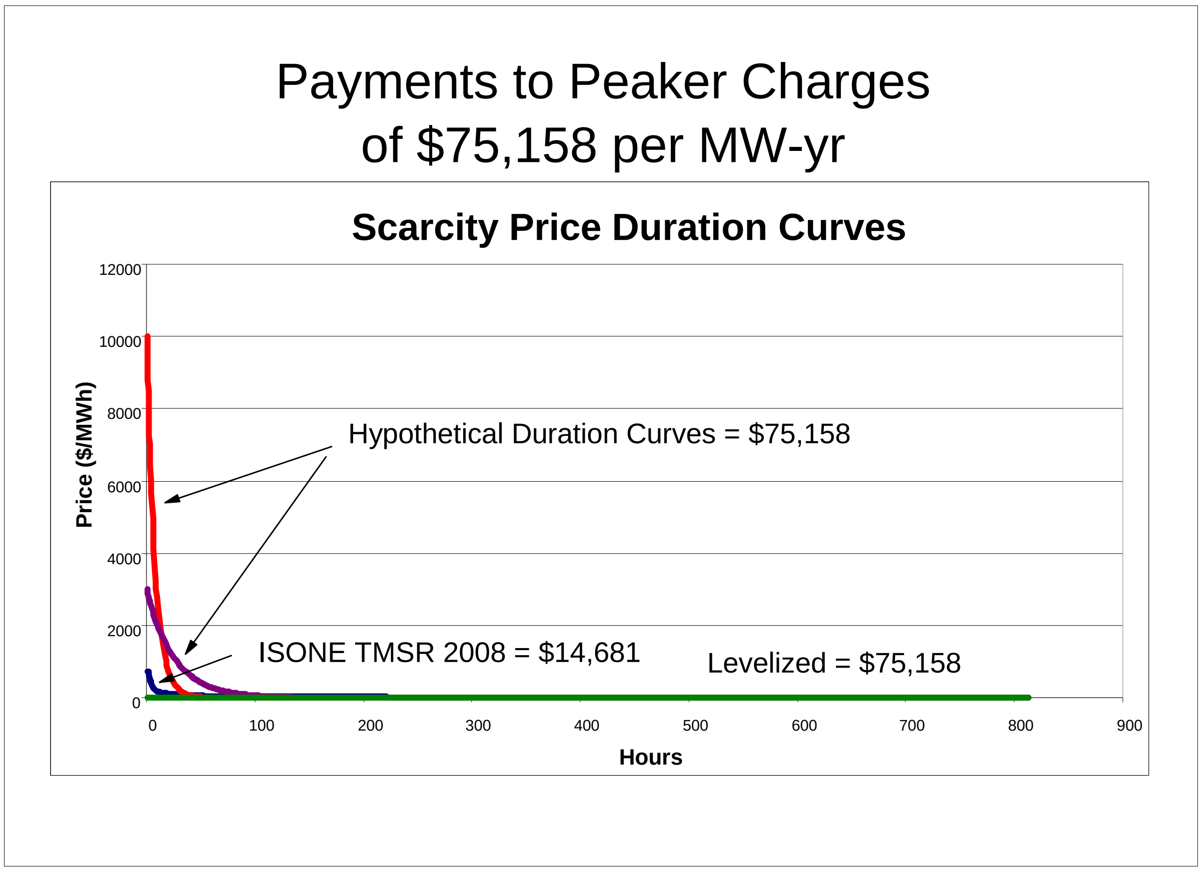


$$p_{\bar{r}_1} = v_1\left(1 - F_1\left(\bar{r}_1 + r_1\right)\right) - v_0\left(1 - F_0\left(r_0 - \bar{r}_1\right)\right)\left(1 - F_1\left(\bar{r}_1 + r_1\right)\right)$$

An interesting question is the frequency of different reserve levels and the interaction with the operating reserve demand curve. This will determine the scarcity price duration curve.



Different scarcity pricing duration curves will determine the contribution of scarcity prices to total payments for energy and reserves. For example, consider the PJM estimate of a fixed charge for a peaker at $75,158 per MW-yr. The hypotheticals illustrate consistent alternative duration curves. These are compared with the actual 2008 price duration curve in ISONE for ten minute spinning reserves (TMSR) for location ID 7000.



Improved pricing through an explicit operating reserve demand curve raises a number of issues.

Demand Response: Better pricing implemented through the operating reserve demand curve would provide an important signal and incentive for flexible demand participation in spot markets.

Price Spikes: A higher price would be part of the solution. Furthermore, the contribution to the “missing money” from better pricing would involve many more hours and smaller price increases.

Practical Implementation: The NYISO, ISONE and MISO implementations dispose of any argument that it would be impractical to implement an operating reserve demand curve. The only issues are the level of the appropriate price and the preferred model of locational reserves.

Operating Procedures: Implementing an operating reserve demand curve does not require changing the practices of system operators. Reserve and energy prices would be determined simultaneously treating decisions by the operators as being consistent with the adopted operating reserve demand curve.

Multiple Reserves: The demand curve would include different kinds of operating reserves, from spinning reserves to standby reserves.

Reliability: Market operating incentives would be better aligned with reliability requirements.

Market Power: Better pricing would remove ambiguity from analyses of high prices and distinguish (inefficient) economic withholding through high offers from (efficient) scarcity pricing derived from the operating reserve demand curve.

Hedging: The Basic Generation Service auction in New Jersey provides a prominent example that would yield an easy means for hedging small customers with better pricing.

Increased Costs: The higher average energy costs from use of an operating reserve demand curve do not automatically translate into higher costs for customers. In the aggregate, there is an argument that costs would be lower.

Compared to a perfect model, there are many simplifying assumptions needed to specify and operating reserve demand curve. The sketch of the operating reserve demand curve(s) in a network could be extended.

- **Empirical Estimation.** Use existing LOLP models or LOLP extensions with networks to estimate approximate LOLP distributions at nodes.
- **Value of Lost Load.** There are different estimates of lost load. For demand curve estimation the relevant value is the marginal of the average VOLL across the group that would first be curtailed in the event of an outage greater than the available reserves.
- **Multiple Periods.** Incorporate multiple periods of commitment and response time. Handled through the usual supply limits on ramping.
- **Operating Rules.** Incorporate up and down ramp rates, deratings, emergency procedures, etc.
- **Pricing incidence.** Charging participants for impact on operating reserve costs, with any balance included in uplift.[11]
- **Minimum Uplift Pricing.** Dispatch-based pricing that resolves inconsistencies by minimizing the total value of the price discrepancies.
- **…**

[11] Brendan Kirby and Eric Hirst, "Allocating the Cost of Contingency Reserves," *The Electricity Journal*, December 2003, 99. 39-47.

William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University and a Director of LECG, LLC. This paper draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Australian Gas Light Company, Avista Energy, Barclays, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, Calpine Corporation, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, Conectiv, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Duquesne Light Company, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, GPU Inc. (and the Supporting Companies of PJM), Exelon, GPU PowerNet Pty Ltd., GWF Energy, Independent Energy Producers Assn, ISO New England, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, JP Morgan, Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario IMO, Pepco, Pinpoint Power, PJM Office of Interconnection, PPL Corporation, Public Service Electric & Gas Company, PSEG Companies, Reliant Energy, Rhode Island Public Utilities Commission, San Diego Gas & Electric Corporation, Sempra Energy, SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, TransÉnergie, Transpower of New Zealand, Westbrook Power, Western Power Trading Forum, Williams Energy Group, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).