RELIABILITY AND SCARCITY PRICING: OPERATING RESERVE DEMAND CURVES (*continued*)

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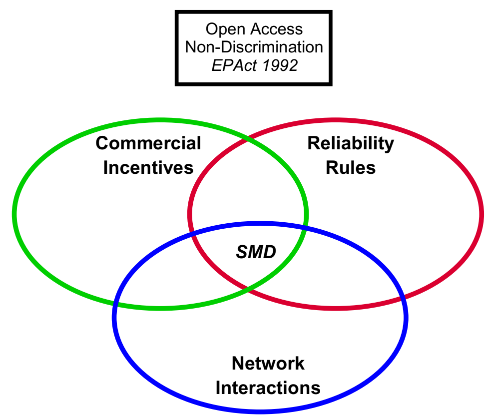
Tension appears in addressing reliability issues, a FERC priority in 2005. Consider the observation from the Blackout Task Force:

> "The need for additional attention to reliability is not necessarily at odds with increasing competition and the improved economic efficiency it brings to bulk power markets. Reliability and economic efficiency can be compatible, but this outcome requires more than reliance on the laws of physics and the principles of economics. It requires sustained, focused efforts by regulators, policy makers, and industry leaders to strengthen and maintain the institutions and rules needed to protect both of these important goals. Regulators must ensure that competition does not erode incentives to comply with reliability requirements, and that reliability requirements do not serve as a smokescreen for noncompetitive practices." (Blackout Task Force Report, April 2004, p. 140.)

- Using markets for public purposes.
- The emphasis should be on investment incentives and innovation, not short-run operational efficiency.
- With workable markets, market participants spending their own money would be better overall in balancing risks and rewards than would central planners spending other people's money.
- If not, electricity restructuring itself would fail the cost-benefit test.

Successful Market Design Challenge



The North American Electric Reliability Council (NERC) enumerated market interface principles.

Market Interface Principles

"Recognizing that bulk electric system reliability and electricity markets are inseparable and mutually interdependent, all Organization Standards shall be consistent with the Market Interface Principles. Consideration of the Market Interface Principles is intended to assure Organization Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy.
2. An Organization Standard shall not give any market participant an unfair competitive advantage.
3. An Organization Standard shall neither mandate nor prohibit any specific market structure.
4. An Organization Standard shall not preclude market solutions to achieving compliance with that standard.
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards."

(NERC, "Reliability and Market Interface Principles," February 25, 2002, ftp://ftp.nerc.com/pub/sys/all_updl/tsc/stf/ReliabilityandMarketInterfacePrinciples.pdf)

A search of the 343 pages of the complete set of NERC reliability standards produces the following hits.

Concept	Search Result
Economic	"For emergency, not economic, reasons." (Attachment 1-EOP-002-0)
Cost	"2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost." (Attachment 1-EOP-002-0)
Price	NA
Tariff Rate	NA

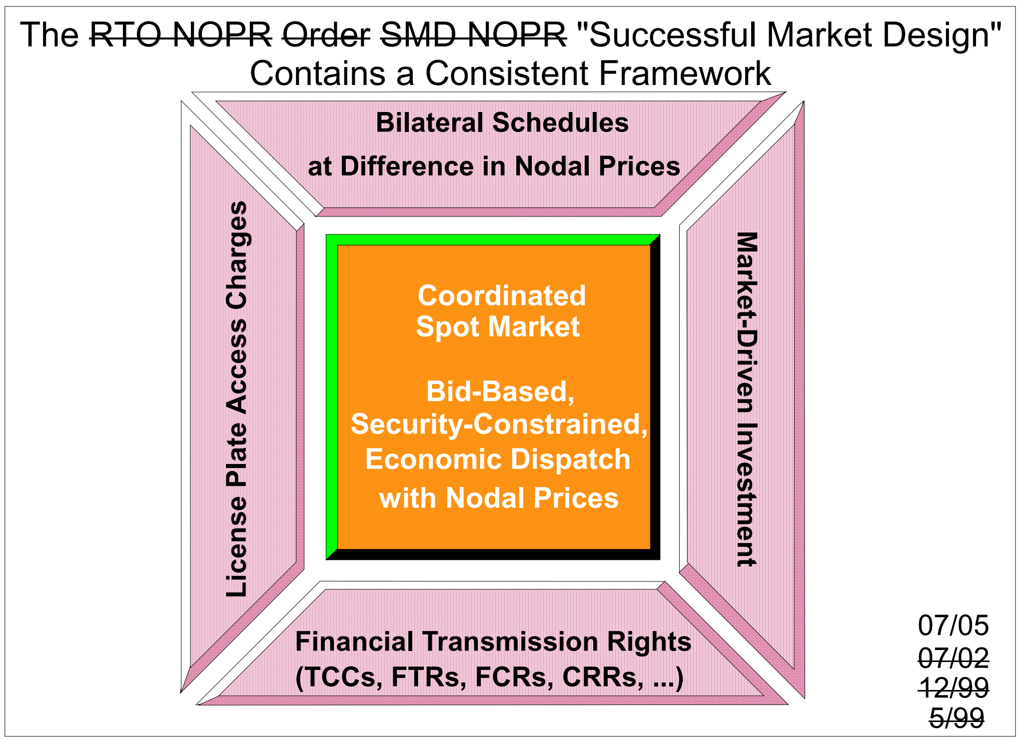
(NERC, "Reliability Standards for the Bulk Electric Systems of North America," February 2005, ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Reliability_Standards_Complete_Set.pdf)

This suggests there is a long way to go in constructing mutual reinforcement between market designs and reliability standards.

Where to begin?[1]

1 Paul Joskow and John Tirole, "Reliability and Competitive Electricity Markets," MIT, December 5, 2005.

The example of successful central coordination, ~~CRT, Regional Transmission Organization (RTO) Millennium Order (Order 2000) Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR),~~ "Successful Market Design" provides a workable market framework that is working in places like New York, PJM in the Mid-Atlantic Region, New England, and the Midwest.



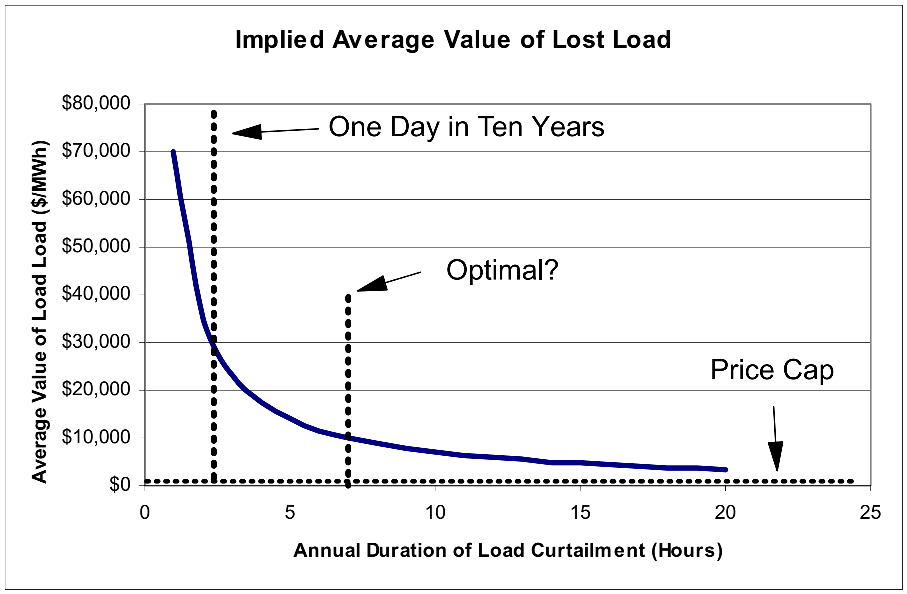
PoolCo…OPCO…ISO…IMO…Transco…RTO… ITP…WMP…: "A rose by any other name …"

What is "security constrained" economic dispatch? The usual market design approach takes reliability standards and limits as fixed constraints limiting the scope of the economic dispatch.

- **Operations**
  - Transmission Contingency Constraints
    - Thermal
    - Voltage (Interface)
    - Stability (Interface)
  - Generation Operating Reserves
- **Planning**
  - Installed Generation Capacity
  - Transmission Capacity Deliverability
- **Limits vs. Tradeoffs**
  - Fixed Limits
  - Price Responsive (e.g. demand curves)

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.

Reliability Standard and Market Disconnect



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

Operating reserve standards typically specify inflexible requirements, often tied to the largest contingency. The PJM case is illustrative.

"5) a) The Mid-Atlantic Spinning Reserve Zone Requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. Mid-Atlantic Area Council (MAAC) standards currently set that amount at 75% of the largest contingency in that Spinning Reserve Zone provided that double the remaining 25% is available as non-synchronized 10-minute reserves.

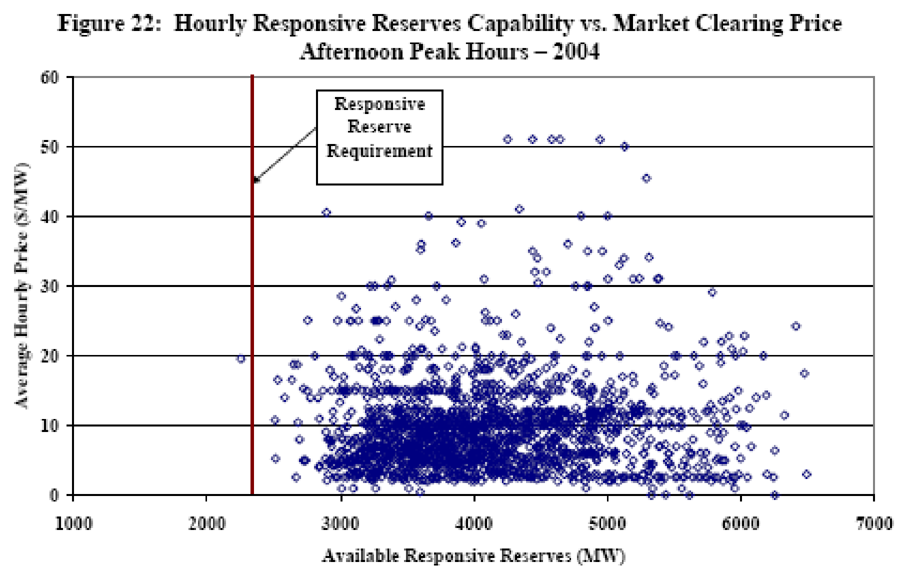
b) The Western Spinning Reserve Zone Requirement is defined as 1.5% of the peak load forecast of the Western Spinning Reserve Market Area for that day.

c) The Northern Illinois Spinning Reserve Zone Requirement is defined as 50% of ComEd's load ratio share of the largest system contingency within MAIN.

d) The Southern Spinning Reserve Zone Requirement is defined as the Dominion load ratio share of the largest system contingency within VACAR, minus the available 15 minute quick start capability within the Southern Spinning Reserve Zone."

(PJM, "Synchronized Reserve Market Business Rules," Revised July 14, 2005, p. 2, http://www.pjm.com/committees/members/downloads/20050714-item3b-synchronized-reserve-mrkt-bus-rules.pdf)

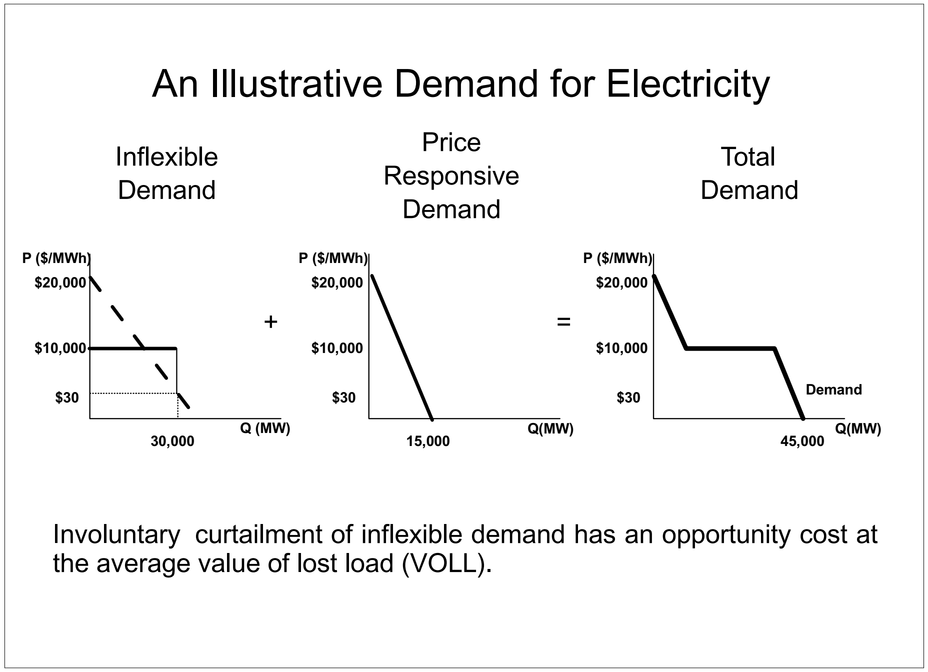
The ERCOT operating reserve standard is a fixed megawatt requirement for 2,300 MW on a 30,000 to 60,000 MW peak system. Price dispersion reflects design features of the ERCOT market.



"This figure indicates a somewhat random pattern of responsive reserves prices in relation to the hourly available responsive reserves capability in real time. In a well functioning-market for responsive reserves, we would expect excess capacity to be negatively correlated with the clearing prices, but this was not the case in 2004. Although a slight negative relationship existed in 2003, the dispersion in prices in both years raises significant issues regarding the performance of this market. Particularly surprising is the frequency with which the price exceeds $10 per MW when the available responsive reserves capability is more than 2,000 MW higher than the requirement. In these hours, the marginal costs of supplying responsive reserves should be zero. These results reinforce the potential benefits promised by jointly optimizing the operating reserves and energy markets, which we would recommend in the context of the alternative markets designs currently under consideration."

(Potomac Economics, Ltd. 2004 State Of The Market Report For The ERCOT Wholesale Electricity Markets, July 2005, p. 22, p .40 http://www.ksg.harvard.edu/hepg/Papers/ERCOT.Wholesale.Electricity.Markets.2004annualreport.pdf).

Existing market economic energy demand curves do not reflect the full value of load. De facto price caps of $250 to $1000/ MWh are far below the average value of load. Implicit demand for inflexible load would define the opportunity costs as the average value of lost load (VOLL)[2].



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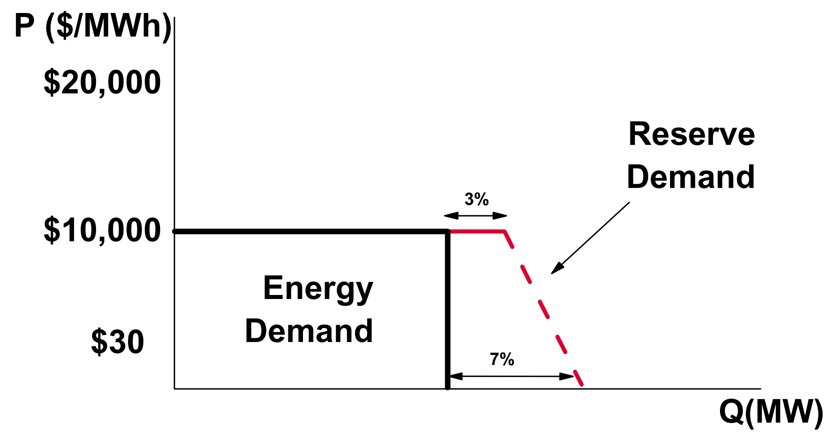
[2] Paul Joskow and John Tirole, "Reliability and Competitive Electricity Markets," MIT, December 5, 2005.

An operating reserve demand curve would reflect differential expected effects on reliability. This is separate from energy demand, and would apply even with fixed energy demand.

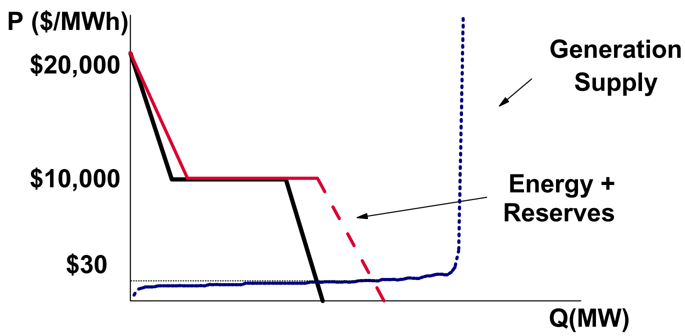
Illustrative Reserve Demand



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.

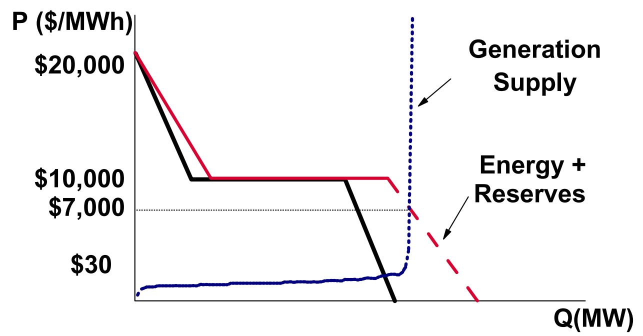
Simultaneous market clearing provides incentives to provide both energy and operating reserves. Prices for reserves and energy that reflected real scarcity conditions would provide stronger incentives to support both reliable operations and adequate investment.

Normal "Energy Only" Market Clearing



When demand is low and capacity available, reserves hit nominal targets at a low price.

Scarcity "Energy Only" Market Clearing



When demand is high and reserve reductions apply, there is a high price.

Locational fixed operating reserve minimums are already familiar practice. The detailed operating rules during reserve scarcity involve many steps. Improved scarcity pricing would accompany introduction of an operating reserve demand curve under dispatch based pricing. Consider a simplified setting.

- **Dispatched-Based Pricing.** Interpret the actual dispatch result as the solution of the reliable economic dispatch problem. Calculate consistent prices from the simplified model.
- **Single Period.** Unit commitment decisions made as though just before the start of the period. Uncertain outcomes determined after the commitment decision, with only redispatch or emergency actions such as curtailment over the short operating period (e.g. less than an hour).
- **Single Reserve Class.** Model operating reserves as committed and synchronized.
- **DC Network Approximation.** Focus on role of reserves but set context of simultaneous dispatch of energy and reserves. A network model for energy, but a zonal model for reserves.

The purpose here is to pursue a further development of the properties of a market model that expands locational reserve requirements to include operating reserve demand curve(s).

The NYISO market design includes locational operating reserve demand curves. The ISONE market design plan calls for locational operating reserve requirements with violation penalties that operate like a demand curve.[3]

[3] Independent Market Advisor, to the New York ISO, "2004 State of the Market Report New York ISO," NYISO, July 2005, p. 59. ISO New England, "2006 Wholesale Markets Plan," September 2005, pp. 16-17.

Begin with an expected value formulation of economic dispatch that might appeal in principle. Given benefit (*B*) and cost (*C*) functions, demand (*d*), generation (*g*), plant capacity (*Cap*), reserves (*r*), commitment decisions (*u*), transmission constraints (*H*), and state probabilities (*p*):

$$\underset{y^i, d^i, g^i, r, u \in (0,1)}{Max} \; p_0 \left(B^0\left(d^0\right) - C^0\left(g^0, r, u\right)\right) + \sum_{i=1}^{N} p_i \left(B^i\left(d^i, d^0\right) - C^i\left(g^i, g^0, r, u\right)\right)$$

$$s.t.$$

$$y^i = d^i - g^i, \quad i = 0, 2, \cdots, N,$$

$$\iota^t y^i = 0, \quad i = 0, 1, 2, \cdots, N,$$

$$H^i y^i \le b^i, \quad i = 0, 1, 2, \cdots, N,$$

$$g^0 + r \le u \bullet Cap^0,$$

$$g^i \le g^0 + r, \quad i = 1, 2, \cdots, N,$$

$$g^i \le u \bullet Cap^i, \quad i = 0, 1, 2, \cdots, N.$$

Suppose there are *K* possible contingencies. The interesting cases have $K \gg 10^3$. The number of possible system states is $N = 2^K$, or more than the stars in the Milky Way. Some approximation will be in order.[4]

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[4] Shams N. Siddiqi and Martin L. Baughman, "Reliability Differentiated Pricing of Spinning Reserve," IEEE Transactions on Power Systems, Vol. 10, No. 3, August 1995, pp.1211-1218. José M. Arroyo and Francisco D. Galiana, "Energy and Reserve Pricing in Security and Network-Constrained Electricity Markets," IEEE Transactions On Power Systems, Vol. 20, No. 2, May 2005, pp. 634-643. François Bouffard, Francisco D. Galiana, and Antonio J. Conejo, "Market-Clearing With Stochastic Security—Part I: Formulation," IEEE Transactions On Power Systems, Vol. 20, No. 4, November 2005, pp. 1818-1826; "Part II: Case Studies," pp. 1827-1835.

Introduce random changes in load and possible lost load l^i in at least some conditions.

$$\underset{y^i,d^i,g^i,r,u\in(0,1)}{Max}\ p_0\left(B^0\left(d^0\right)-C^0\left(g^0,r,u\right)\right)+\sum_{i=1}^{N}p_i\left(B^i\left(d^o+\varepsilon^i-l^i,d^0\right)-C^i\left(g^i,g^0,r,u\right)\right)$$

$$\begin{aligned}
&s.t.\\
&\quad y^0=d^0-g^0,\\
&\quad y^i=d^0+\varepsilon^i-g^i-l^i,\quad i=1,2,\cdots,N,\\
&\quad \iota^t y^i=0,\quad i=0,1,2,\cdots,N,\\
&\quad H^i y^i\le b^i,\quad i=0,1,2,\cdots,N,\\
&\quad g^0+r\le u\bullet Cap^0,\\
&\quad g^i\le g^0+r,\quad i=1,2,\cdots,N,\\
&\quad g^i\le u\bullet Cap^i,\quad i=0,1,2,\cdots,N.
\end{aligned}$$

Simplify the benefit and cost functions:

$$B^i\left(d^o+\varepsilon^i-l^i,d^0\right)\approx B^0\left(d^0\right)+k_d^i-v^t l^i \qquad , \qquad C^i\left(g^i,g^0,r,u\right)\approx C^0\left(g^0,r,u\right)+k_g^i .$$

This produces an approximate objective function:

$$p_0\left(B^0\left(d^0\right)-C^0\left(g^0,r,u\right)\right)+\sum_{i=1}^{N}p_i\left(B^i\left(d^o-l^i,d^0\right)-C^i\left(g^i,g^0,r,u\right)\right)=B^0\left(d^0\right)-C^0\left(g^0,r,u\right)+\sum_{i=1}^{N}p_i\left(k_d^i-k_g^i\right)-v^t\sum_{i=1}^{N}p_i l^i .$$

The revised formulation highlights the pre-contingency objective function and the role of the value of the expected undeserved energy.

$$\underset{y^i, d^i, g^i, r, u \in (0,1)}{Max} B^0\left(d^0\right) - C^0\left(g^0, r, u\right) - v^t \sum_{i=1}^{N} p_i l^i$$

$$s.t.$$

$$y^0 = d^0 - g^0,$$

$$y^i = d^0 + \varepsilon^i - g^i - l^i, \quad i = 1, 2, \cdots, N,$$

$$\iota^t y^i = 0, \quad i = 0, 1, 2, \cdots, N,$$

$$H^i y^i \le b^i, \quad i = 0, 1, 2, \cdots, N,$$

$$g^0 + r \le u \bullet Cap^0,$$

$$g^i \le g^0 + r, \quad i = 1, 2, \cdots, N,$$

$$g^i \le u \bullet Cap^i, \quad i = 0, 1, 2, \cdots, N.$$

There are still too many system states.

Define the optimal value of expected unserved energy (VEUE) as the result of all the possible optimal post-contingency responses given the pre-contingency commitment and scheduling decisions.

$$VEUE\left(d^0, g^0, r, u\right) = \underset{y^i, d^i, g^i, r}{Min} \; v^t \sum_{i=1}^{N} p_i l^i$$

$$\begin{aligned}
&s.t. \\
&\quad y^i = d^0 + \varepsilon^i - g^i - l^i, \quad i = 1, 2, \cdots, N, \\
&\quad \iota^t y^i = 0, \quad i = 1, 2, \cdots, N, \\
&\quad H^i y^i \le b^i, \quad i = 1, 2, \cdots, N, \\
&\quad g^0 + r \le u \bullet Cap^0, \\
&\quad g^i \le g^0 + r, \quad i = 1, 2, \cdots, N, \\
&\quad g^i \le u \bullet Cap^i, \quad i = 1, 2, \cdots, N.
\end{aligned}$$

This second stage problem subsumes all the redispatch and curtailment decisions over the operating period after the commitment and scheduling decisions.

The expected value formulation reduces to a much more manageable scale with the introduction of the implicit VEUE function.

$$
\begin{aligned}
&\underset{y^0, d^0, g^0, r, u \in (0,1)}{Max} \; B^0\left(d^0\right) - C^0\left(g^0, r, u\right) - VEUE\left(d^0, g^0, r, u\right) \\
&s.t. \\
&\quad y^0 = d^0 - g^0, \\
&\quad H^0 y^0 \le b^0, \\
&\quad g^0 + r \le u \bullet Cap^0, \\
&\quad \iota^t y^0 = 0, \\
&\quad g^0 \le u \bullet Cap^0.
\end{aligned}
$$

The optimal value of expected unserved energy which defines the demand for operating reserves.

Ignore the network features for the first illustration. Assume all the load and generations is at a single location. 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*).

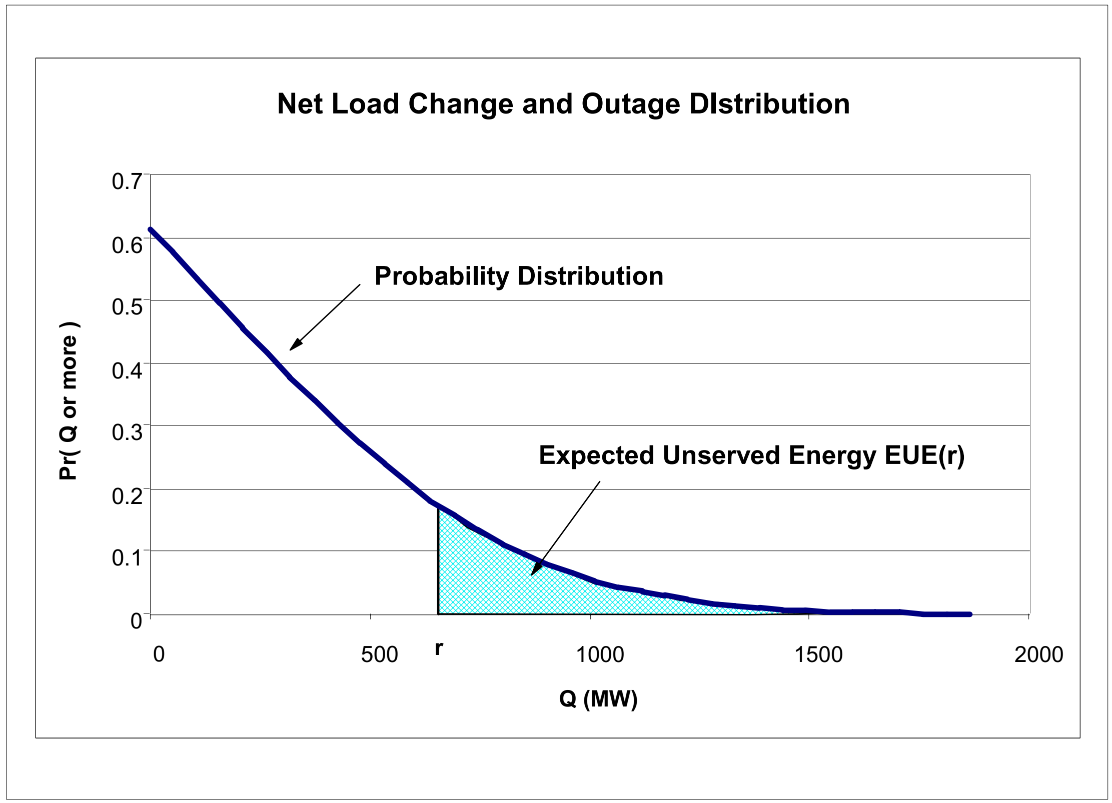
Suppose the *VOLL* per MWh is v. Then we can obtain the *EUE* and its total value (*VEUE*) as:

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

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

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

The real changes may not be continuous, but it is common to apply continuous approximations.



The distribution of load and facility outages compared to operating reserves determines the LOLP.

A reasonable approximation is that the change in load is normally distributed: $\Delta\, Load \sim N\left(0, \sigma_L^2\right)$.

The outage distribution is more complicated and depends on many factors, including the unit commitment. Suppose that $o_j = 0,1$ is a random variable where $o_j = 1$ represents a unit outage. The probability of an outage in the monitored period, given that plant was available and committed at the start of the period $(u_j = 1)$ is ω_j, typically a small value on the order of less than 10^{-2}:

$$Outage = \sum_j u_j Cap_j o_j,$$

$$\Pr\left(o_j = 1 \middle| u_j = 1\right) = \omega_j.$$

A common approximation of $\Pr(Outage)$ is a mixture of distributions with a positive probability of no outage and a conditional distribution of outages that follows an exponential distribution.[5]

$$\Pr\left(Outage = 0\right) = p_0, \Pr\left(Outage > x\right) = \left(1 - p_0\right) e^{-\lambda x}.$$

The combined distribution for change in load and outages can be complicated.[6] In application, this distribution might be estimated numerically, possibly from Monte Carlo simulations.

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[5] Debabrata Chattopadhyay and Ross Baldick, "Unit Commitment with Probabilistic Reserve," IEEE, Power Engineering Society Winter Meeting, Vol. 1, pp. 280-285.

[6] Guy C. Davies, Jr., and Michael H. Kuttner, "The Lagged Normal Family Of Probability Density Functions Applied To Indicator-Dilution Curves," Biometrics, Vol. 32, No. 3, September 1976, pp. 669-75.

For sake of the present illustration, make a simplifying assumption that the outage distribution is approximated by a normal distribution.

$$Outage \sim N\left(\mu_O, \sigma_O^2\right).$$

Then with operating reserves *r*, the distribution of the lost load is

$$LOLP = \Pr\left(\Delta\ Load + Outage \geq r\right) = \bar{F}_{LOL}\left(r\right)$$
$$= \bar{\Phi}\left(r \middle| \mu_O, \sigma_O^2 + \sigma_L^2\right) = 1 - \Phi\left(r \middle| \mu_O, \sigma_O^2 + \sigma_L^2\right).$$

Here $\Phi\left(r \middle| \mu_O, \sigma_O^2 + \sigma_L^2\right)$ is the cumulative normal distribution with mean and variance $\mu_O, \sigma_O^2 + \sigma_L^2$

$$EUE\left(r\right) = \int_r^\infty \bar{\Phi}\left(x \middle| \mu_O, \sigma_O^2 + \sigma_L^2\right) dx.$$

$$VEUE\left(r\right) = v \int_r^\infty \bar{\Phi}\left(x \middle| \mu_O, \sigma_O^2 + \sigma_L^2\right) dx.$$

This gives the implied reserve inverse demand curve as

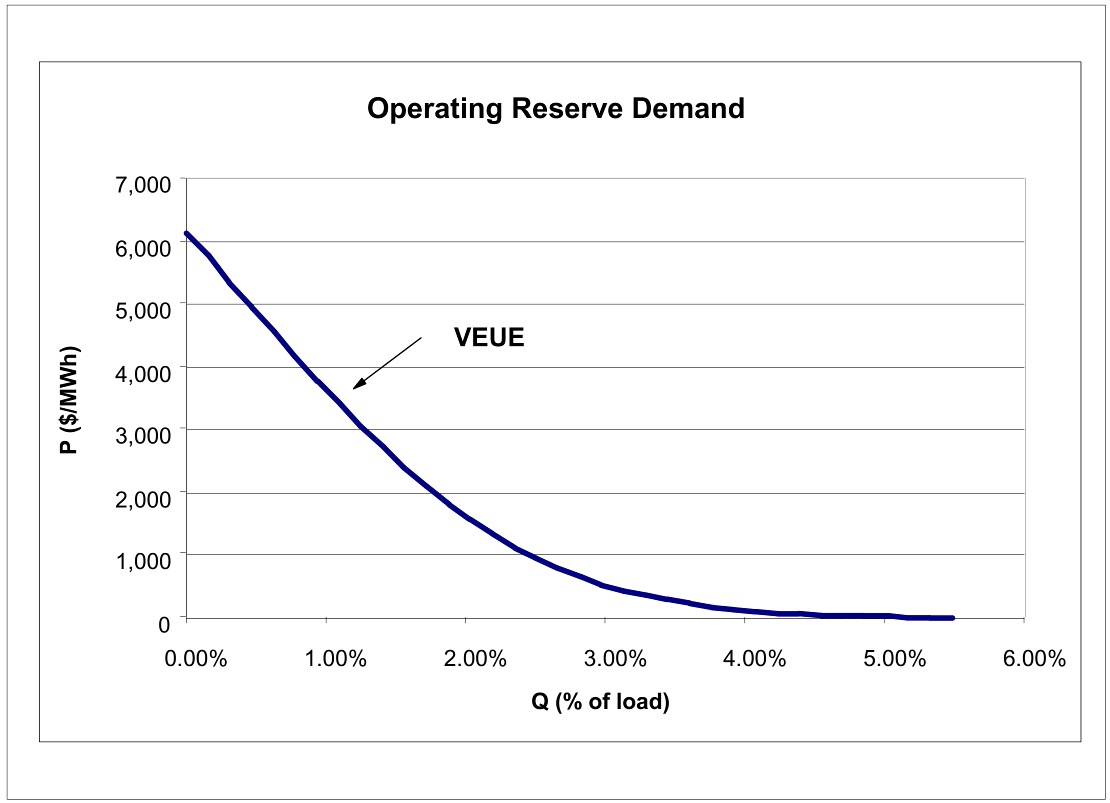
$$Operating\ Reserve\ Demand\ Price\left(r\right) = P_{OR}\left(r\right) = v\bar{\Phi}\left(r \middle| \mu_O, \sigma_O^2 + \sigma_L^2\right).$$

The probabilistic demand for operating reserves reflects the cost and probability of lost load.

$$Operating\ Reserve\ Demand\ Price(r) = P_{OR}(r) = v\bar{\Phi}\left(r \middle| \mu_O, \sigma_O^2 + \sigma_L^2\right).$$

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.

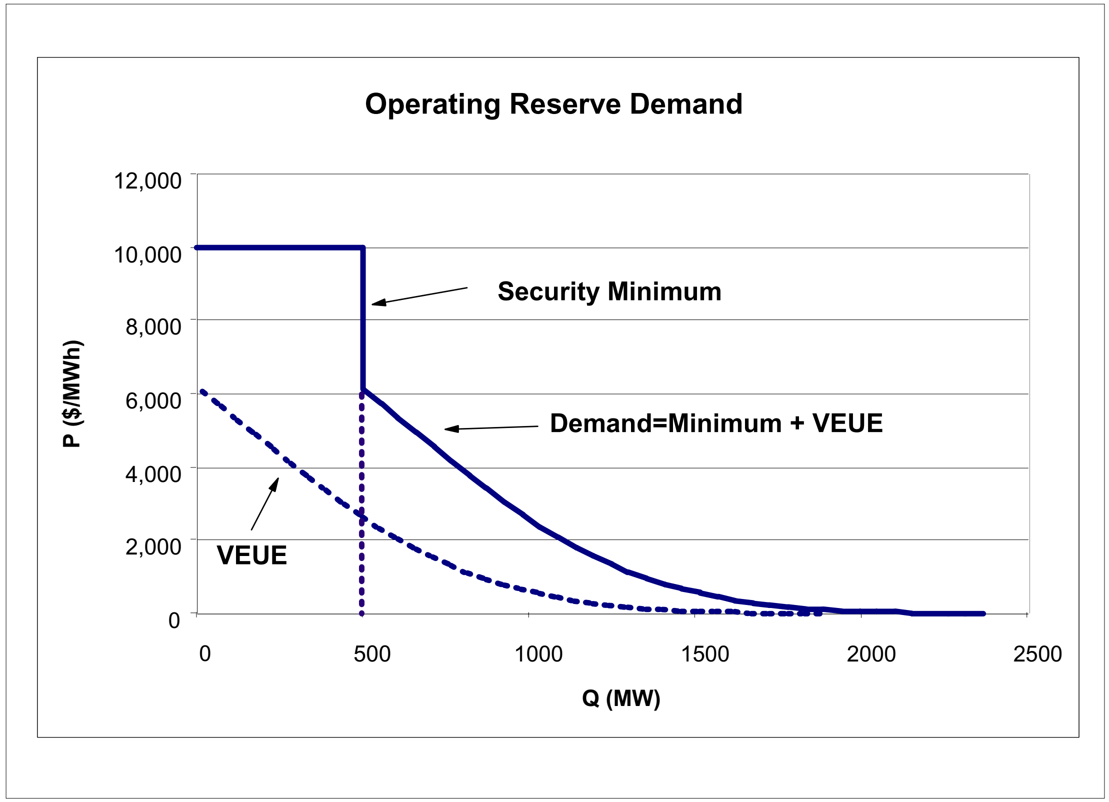
The deterministic approach to security constrained economic dispatch includes lower bounds on the required reserve to ensure that for a set of monitored contingencies (e.g., an n-1 standard) there is sufficient operating reserve to maintain the system for an emergency period.

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.



In a network, security constrained economic dispatch includes a set of monitored transmission contingencies, K_M, with the transmission constraints on the pre-contingency flow determined by conditions that arise in the contingency.

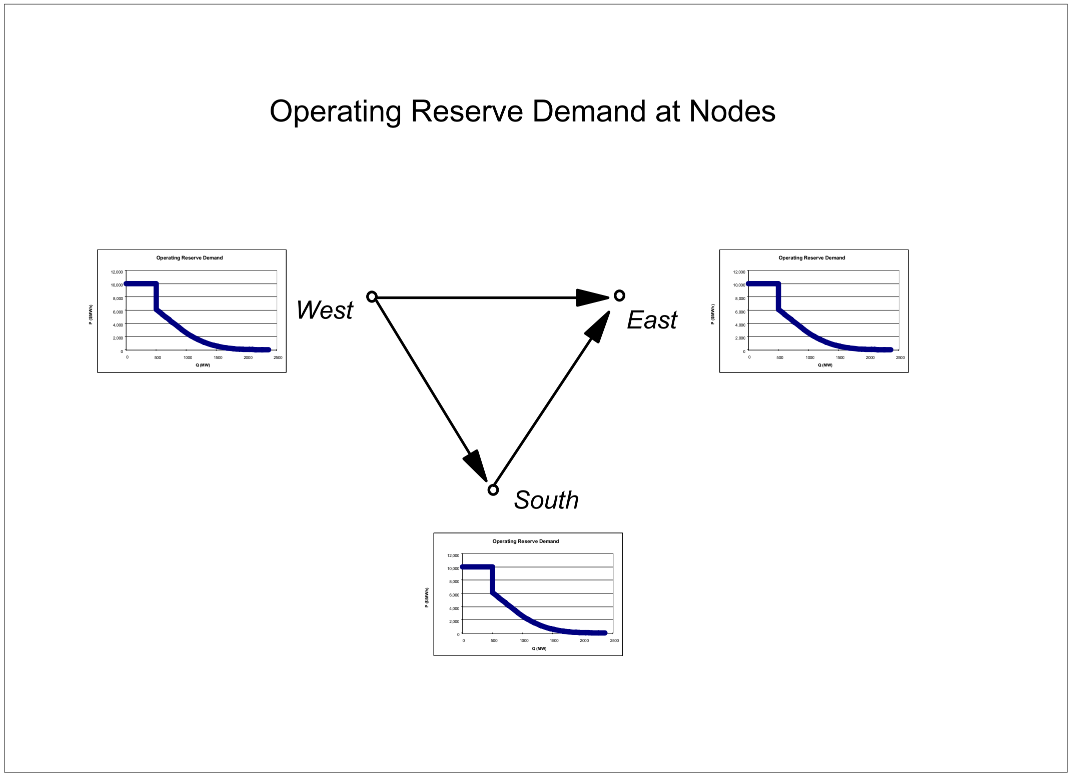
$$H^i y^0 \leq \tilde{b}^i, \quad i = 1, 2, \cdots, K_M.$$

The security constrained economic dispatch problem becomes:

$$\begin{aligned}
&\underset{y^0, d^0, g^0, r, u \in (0,1)}{Max} B^0\left(d^0\right) - C^0\left(g^0, r, u\right) - VEUE\left(d^0, g^0, r, u\right) \\
&s.t. \\
&\quad y^0 = d^0 - g^0, \\
&\quad H^0 y^0 \leq b^0, \\
&\quad H^i y^0 \leq \tilde{b}^i, \quad i = 1, 2, \cdots, K_M, \\
&\quad g^0 + r \leq u \bullet Cap^0, \\
&\quad r \geq r_{Min}\left(d^0, g^0, u\right) \\
&\quad \iota^t y^0 = 0, \\
&\quad g^0 \leq u \bullet Cap^0.
\end{aligned}$$

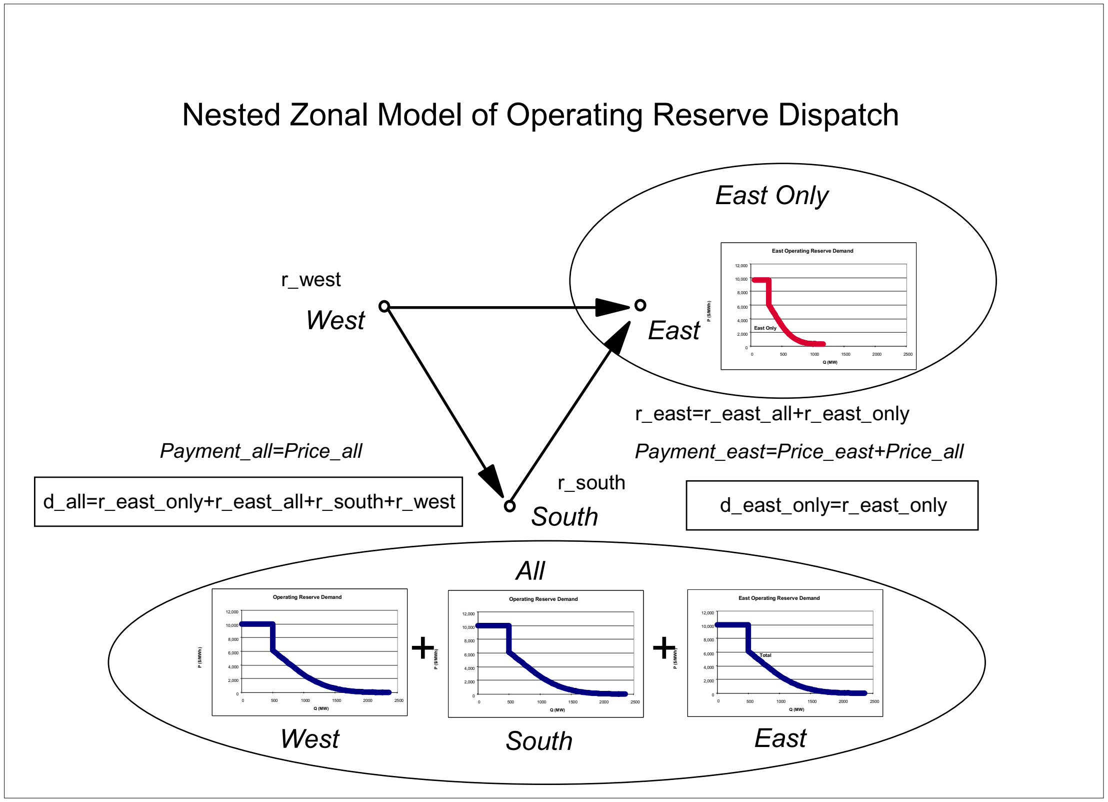
If we could convert each node to look like the single location examined above, the approximation of *VEUE*, would repeat the operating reserve demand curve at each node.

Suppose that the *LOLP* distribution at each node could be calculated.[7] This would give rise to an operating reserve demand curve at each node.



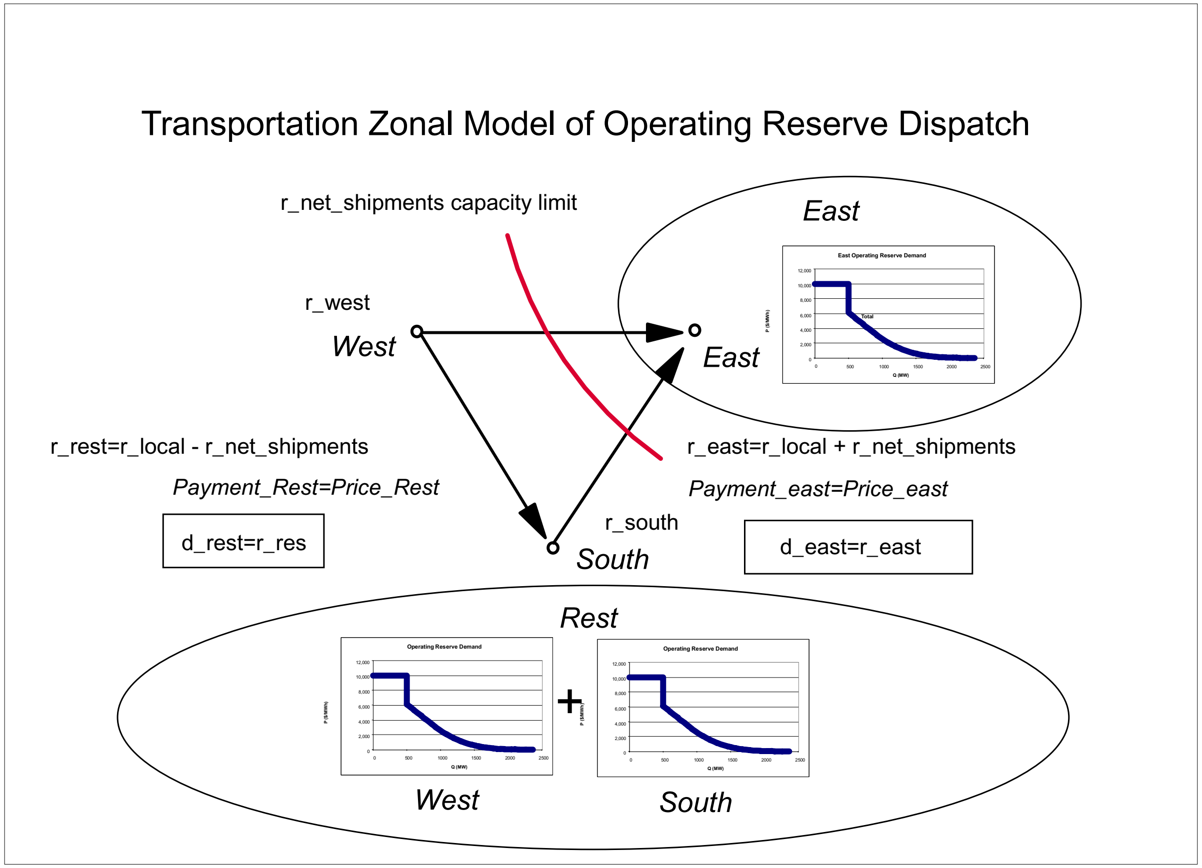
[7] Eugene G. Preston, W. Mack Grady, Martin L. Baughman, "A New Planning Model for Assessing the Effects of Transmission Capacity Constraints on the Reliability of Generation Supply for Large Nonequivalenced Electric Networks," IEEE Transactions on Power Systems, Vol. 12, No. 3, August 1997, pp. 1367-1373. 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.

The next piece is a model of simultaneous dispatch of operating reserves and energy. One approach for the operating reserve piece is a nested zonal model (e.g., NYISO reserve pricing).

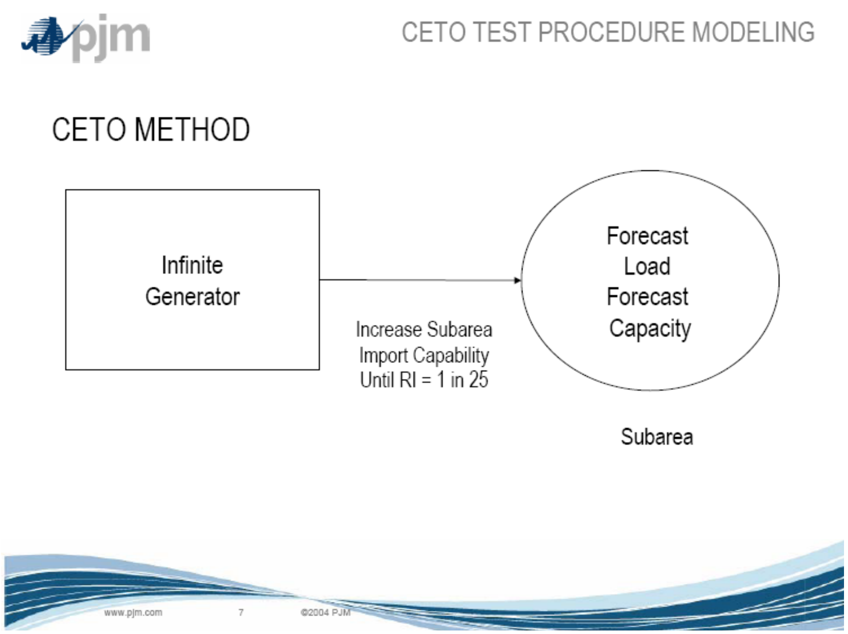


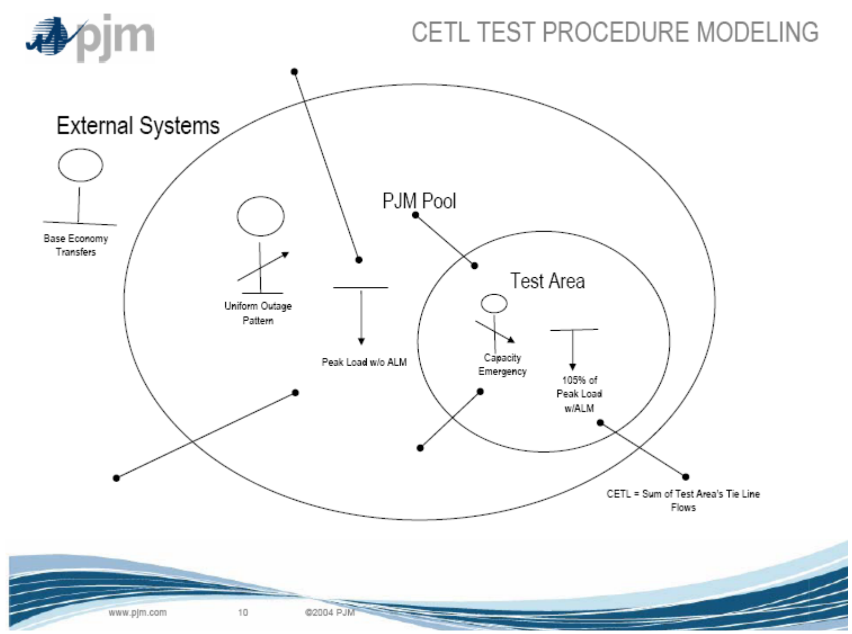
The result is that the input operating reserve price functions are additive premiums that give rise to an implicit operating reserve demand curves with higher prices.

An alternative approach would be to overlay a transportation model with interface transfer limits on operating reserve "shipments." The resulting prices are on the demand curves, but the model requires estimation of the (dynamic) transfer capacities. This is similar to the PJM installed capacity deliverability model.



The PJM deliverability definitions Capacity Emergency Transfer Objective (CETO) and Capacity Emergency Transfer Limit (CETL) use a network model with higher standards to set interface limit.





(PJM Planning Committee, "PJM CETO/CETL Methods," March 29, 2004.)

"Under PJM's RPM proposal, LDAs will be determined using the same load deliverability analyses performed by PJM in the RTEP process, i.e., the comparison of CETO and CETL using a transmission-related LOLE of 1 day in 25 years. Based on these analyses, the LDAs will be those areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations, or stability limitations."

(Steven R. Herling, "Affidavit of Steven R. Herling on Behalf of PJM Interconnection, L.L.C.," August 31, 2005, p. 11.)

Compared to a perfect model, there are many simplifying assumptions needed to specify and operating reserve demand curve. Compared to what is done in current market designs, using the operating reserve demand framework for consistent dispatch-based pricing should be an improvement. 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.
- **Multiple Periods.** Incorporate multiple periods of commitment and response time (e.g., 10 min, 30 min.)
- **Multiple Reserve Classes.** Derive related demand curves for multiple classes of reserves (spinning and synchronized, spinning and nonsynchronized, quick start, 30 minute reserve, and so on).
- **Operating Rules.** Incorporate up and down ramp rates, deratings, emergency procedures, etc.
- **Minimum Uplift Pricing.** Dispatch-based pricing that resolves inconsistencies by minimizing the total value of the price discrepancies.
- **…**

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