ELECTRICITY MARKET HYBRIDS: MIXED MARKET DESIGN, REGULATION AND INVESTMENT

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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.**
  - **Retail and Wholesale Electricity Systems.**
  - **Market Power Mitigation.**
  - **Coordination for Competition.**

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

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:

> "National policy for many years has been, and continues to be, to foster competition in wholesale power markets. As the third major federal law enacted in the last 30 years to embrace wholesale competition, the Energy Policy Act of 2005 (EPAct 2005) strengthened the legal framework for continuing wholesale competition as federal policy for this country.
>
> The Commission's core responsibility is to 'guard the consumer from exploitation by non-competitive electric power companies.' The Commission has always used two general approaches to meet this responsibility—regulation and competition. The first was the primary approach for most of the last century and remains the primary approach for wholesale transmission service, and the second has been the primary approach in recent years for wholesale generation service.
>
> The Commission has never relied exclusively on competition to assure just and reasonable rates and has never withdrawn from regulation of wholesale electric markets. Rather, the Commission has shifted the balance of the two approaches over time as circumstances changed. Advances in technology, exhaustion of economies of scale in most electric generation, and new federal and state laws have changed our views of the right mix of these two approaches. Our goal has always been to find the best possible mix of regulation and competition to protect consumers from the exercise of monopoly power."[1]

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.

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[1] Federal Energy Regulatory Commission, "Wholesale Competition in Regions with Organized Electricity Markets," Advanced Notice of Proposed Rulemaking, Dockets RM07-19-000 and AD07-7-000, June 22, 2007, pp. 4-5.

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

- **Little “r’ regulation:**

  Design rules and policies that are the “best possible mix” 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:**

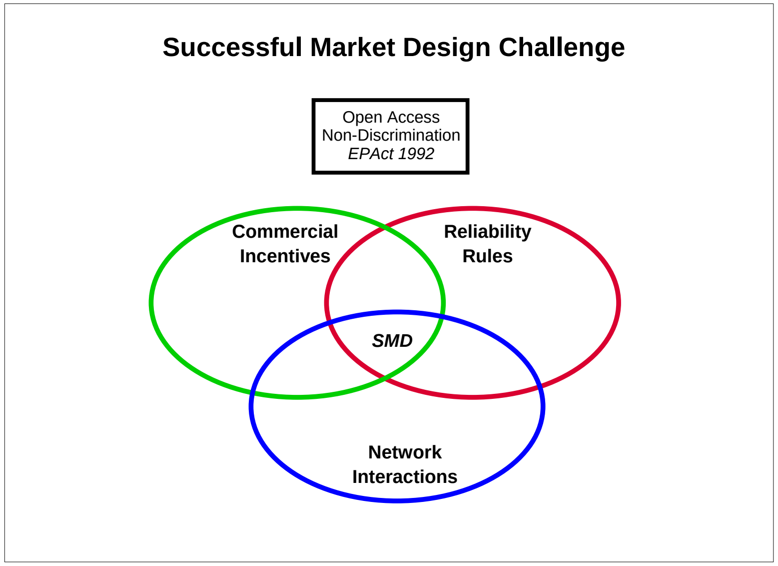
  Frame every problem in its own terms—inadequate demand response, insufficient infrastructure investment, or market power—and design ad hoc regulatory fixes that accumulate to undermine market incentives. This creates a larger slippery slope problem, where one ad hoc solution creates the need for another, 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 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.)

- 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.



There have been repeated attempts to rethink the role of markets and Regional Transmission Organizations (RTOs). The demands of electricity markets impose many requirements and challenges. As a regulated provider of monopoly services, an RTO will never have complete freedom of action. An RTO must provide certain functions to support markets under open access and non-discrimination.

- **Necessary functions for energy markets.**
  - Real-time, bid-based, security constrained economic dispatch with locational prices.
- **Necessary functions for energy markets with effective long-term hedges.**
  - Financial transmission rights (FTRs).
- **Valuable functions for energy markets with effective long-term hedges.**
  - Day-ahead energy market with associated reliability unit commitment.
  - Transmission planning and investment protocols.
- **Necessary features of everything else**
  - Rules and pricing incentives compatible with the above.
    - Ancillary Services
    - Resource Adequacy

This is not new news. A review highlights the key issues.

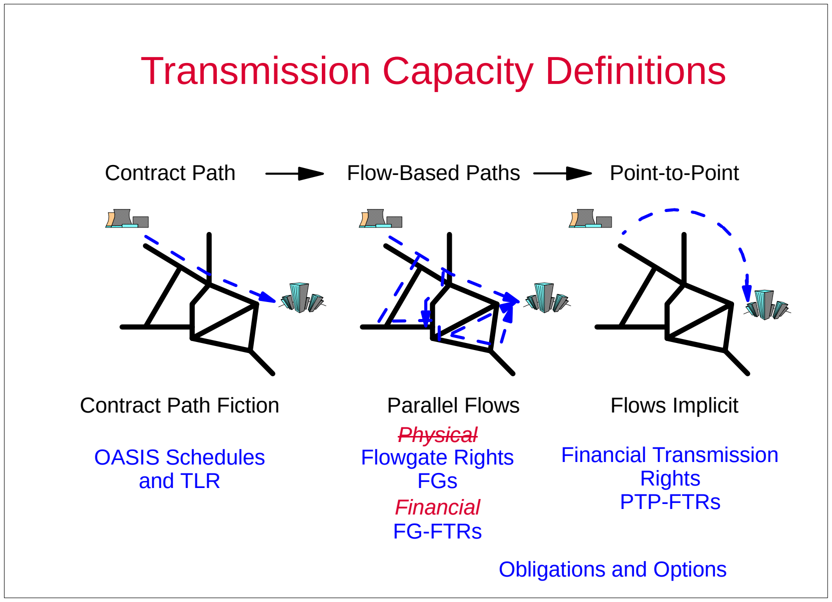
The evolution of electricity restructuring thread ...

The "Contract Path" won't work in theory, but will it work in practice?

- **Order 888, 1996.** Non-discrimination, Open Access to Transmission. Contract path fiction would not work in theory.

- **Capacity Reservation Tariff (CRT), 1996.** A new model.

  "The proposed capacity reservation open access transmission tariff, if adopted, would replace the open access transmission tariff required by the Commission ..."[2]



- **NERC Transmission Loading Relief (TLR), 1997.** The unscheduling system to complement Order 888.

- **EPAct 2005.** Continued support for competitive markets but conflicting signals on market design.

- **Order 890 Reform 2007.** Too little. Too late?

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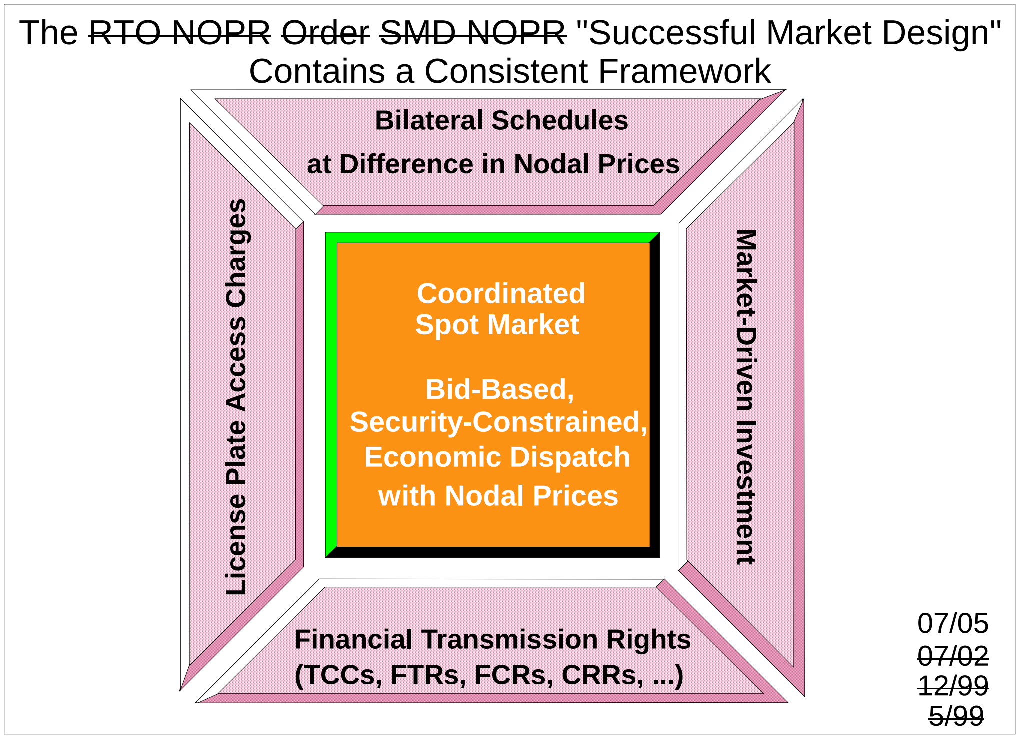
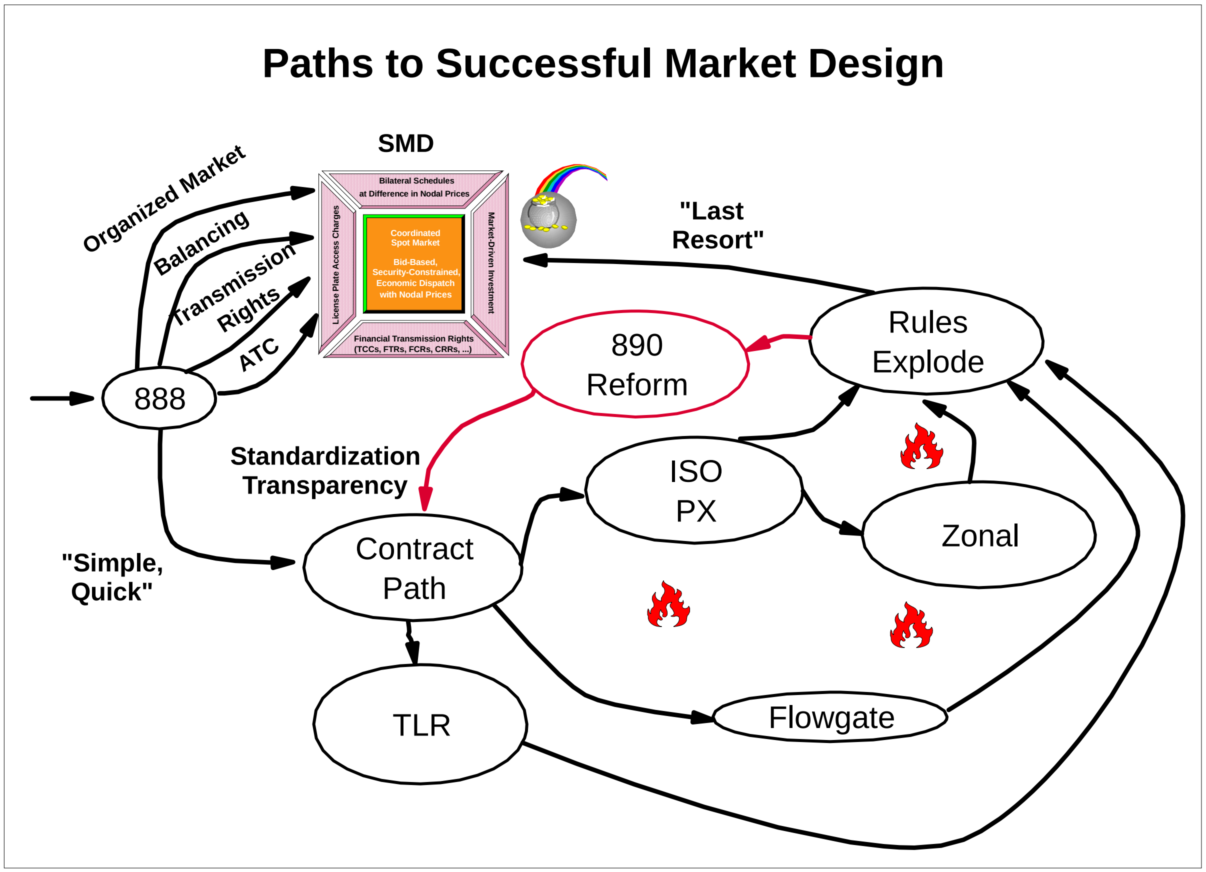
[2] Federal Energy Regulatory Commission, "Capacity Reservation Open Access Transmission Tariffs," Notice of Proposed Rulemaking, RM96-11-000, Washington DC, April 24, 1996, p. 1.

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 …"

The path to successful market design can be circuitous and costly. The FERC "reforms" in Order 890 illustrate "path dependence," where the path chosen constrains the choices ahead. Can Order 890 be reformed to overcome its own logic? Or is FERC trapped in its own loop flow?



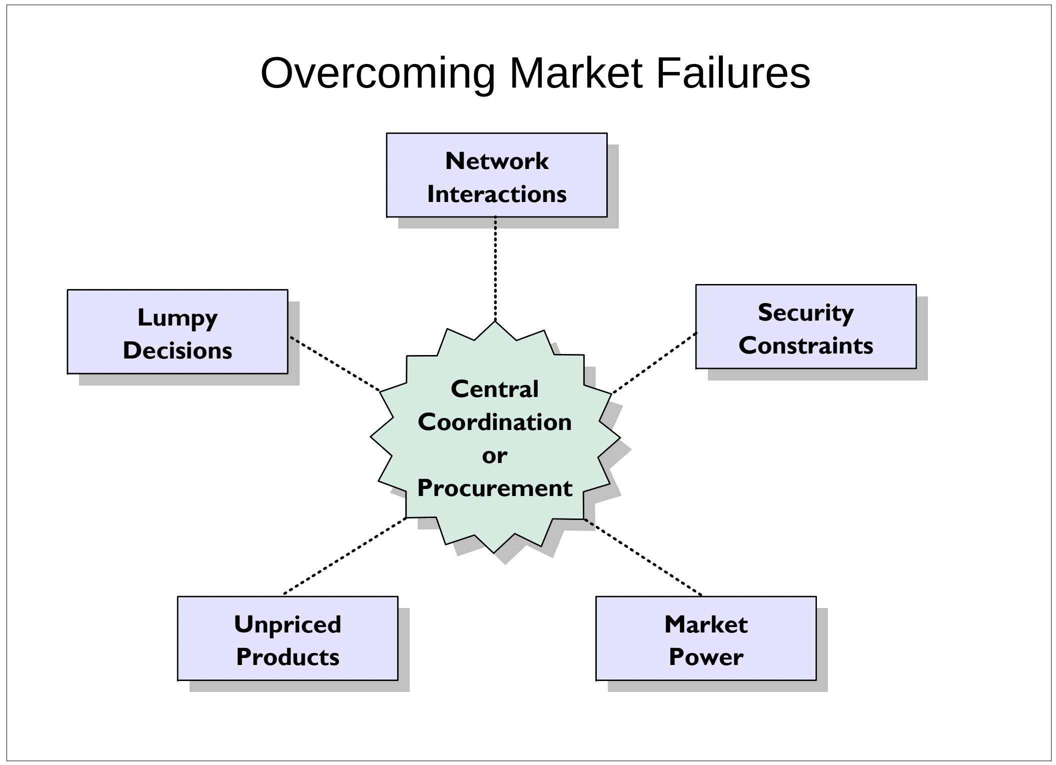
The need for central institutions arises from the existence of prominent forms of market failure. The challenge is to address market failures while preserving the market as the default.

Market defects rise in practical implementation. Approximations and misplaced assumptions revealed through operating experience.

Market failures are inherent from the limits of markets. Real markets transcend the fuzzy boundaries of workable competitive markets.

A dangerous definition of market failure: "The market fails to do what the central planner wants."

Focus on market design and market failures. Better to fix a bad design than to micromanage bad decisions.



Be afraid of the reflexive market intervention that sows the seeds of more intervention. Intervene where needed, and know how to stop. There are examples of interventions that fix market defects or overcome market failure without overturning the market.

Guidelines for design of electricity market institutions include:

- Define Products and Services Consistent with Real Operations.
- Create Property Rights.
- Establish Consistent Pricing Mechanisms.
- Design Central Institutions to Emulate Efficient Market Operations and Incentives.
- Target Structure and Scope of Central Interventions to Address Market Failures.
- Set Principled Limits for Interventions Based on the Nature of the Market Failure.
- Maintain the Goal of Workable, not Perfect, Markets.

The demand for action by regulators
demands that regulators keep their eye on the ball.

Focus on market design and market failures. Better to fix a bad design than to micromanage bad decisions.

Be afraid of the reflexive market intervention that sows the seeds of intervention. Good advice might be: "Don't just do something, stand there." Better advice would be: "Look, and look hard, before you leap."

Intervene where needed, and know how to stop!

Wherever market participants have a choice, it is critical to define property rights and get the prices right. Wherever there are central mandates, it is important to design the rules and prices to be consistent with the fundamental market design. For example:

- **Get the Prices Right**
  - Scarcity pricing, demand participation, and resource adequacy.
  - Operating reserve demand curves.
  - Minimum uplift pricing and lumpy decisions.
- **Support Investment**
  - Transmission planning and investment.
  - Argentine transmission investment model.
- **Mitigate Market Power**
  - Protect consumers from the exercise of market power.
  - Bid caps with adequate scarcity pricing.
  - Hedging contracts for default service.

Balancing little "r" regulation through market design and decentralized decisions, and big "R" regulation through mandates and socialized costs.

Consider two cases of interest that present difficult challenges for regulators.

- **Market Defect: Scarcity Pricing**

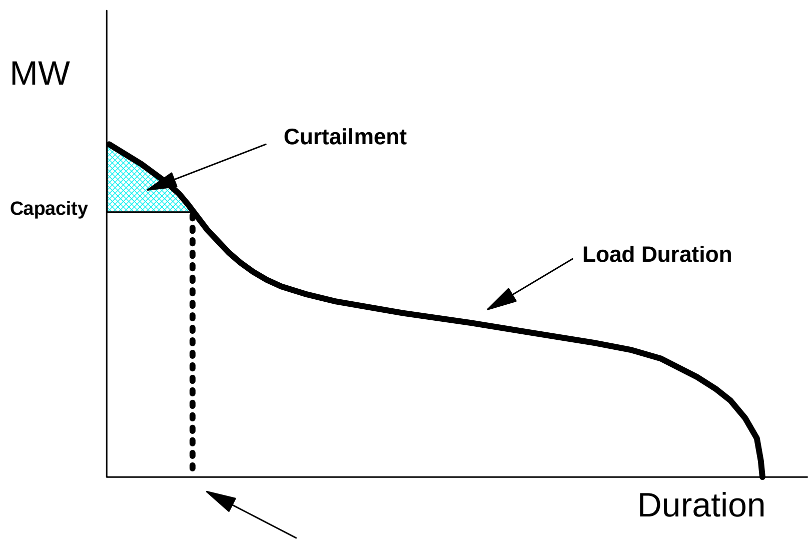
  Better scarcity pricing to support resource adequacy.

- **Market Failure: Transmission Investment**

  Regulatory mandates for lumpy transmission mixed with market-based investments.

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

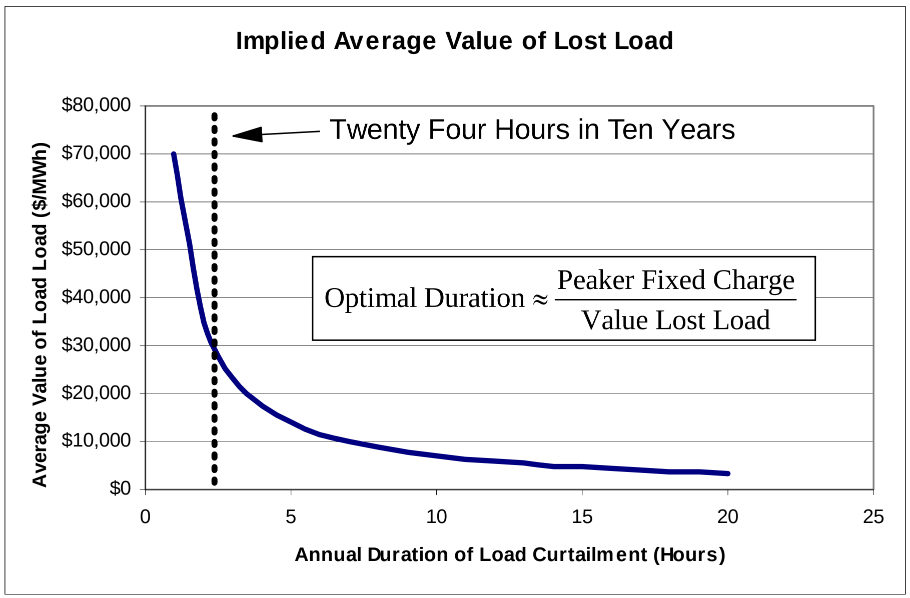


$$\text{Optimal Duration} \approx \frac{\text{Peaker Fixed Charge}}{\text{Value Lost Load}}$$

(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.

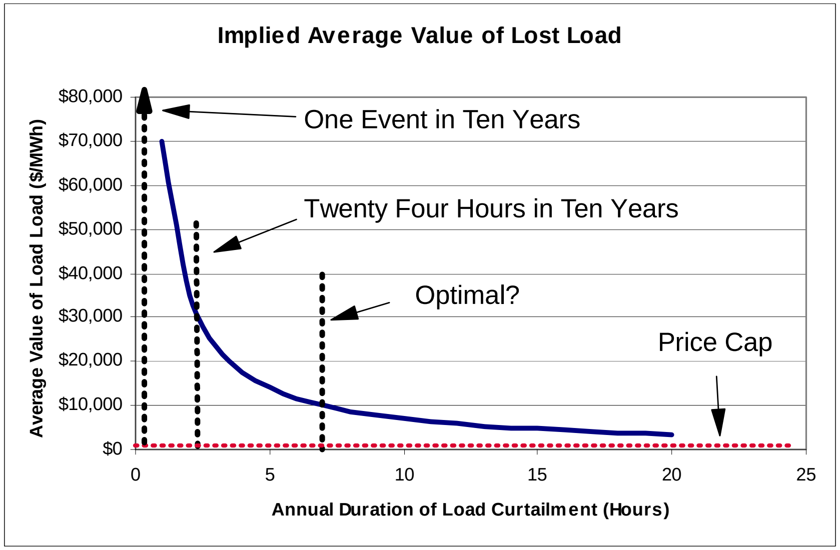
Reliability Planning Standard
and Value of Lost Load



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.

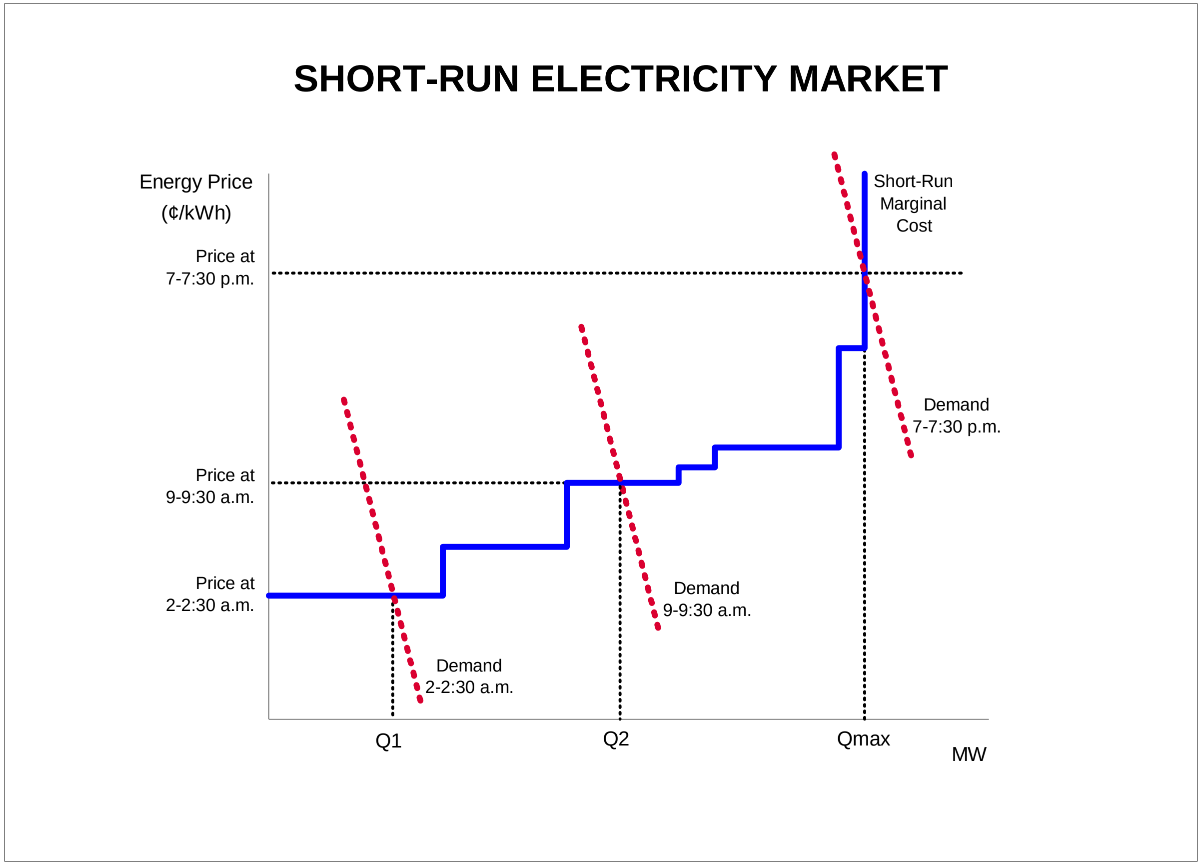
Reliability Standard and Market Disconnect



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

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

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 big "R" regulatory solution calls for capacity mandates. The small "r" approach addresses the pricing problem.

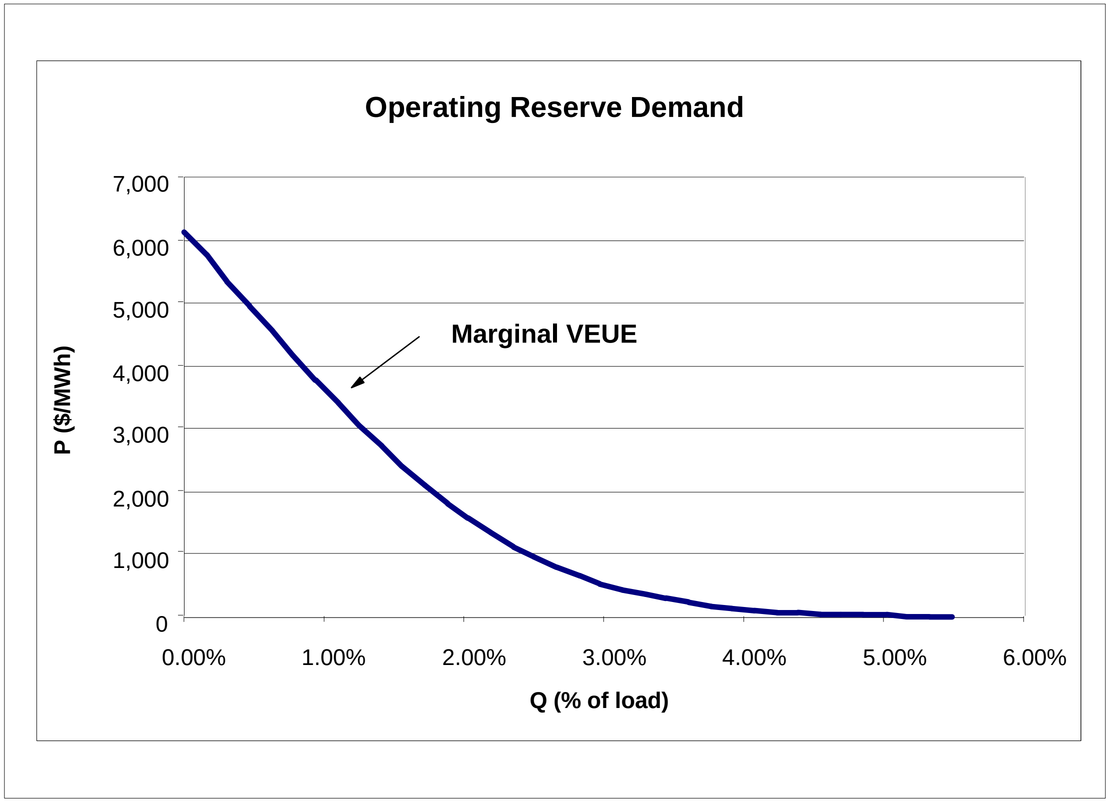


Operating reserve demand is a complement to energy demand for electricity. The probabilistic demand for operating reserves reflects the cost and probability of lost load. Pricing operating reserves could provide the missing money.

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. Total value is of same magnitude as the cost of meeting load.

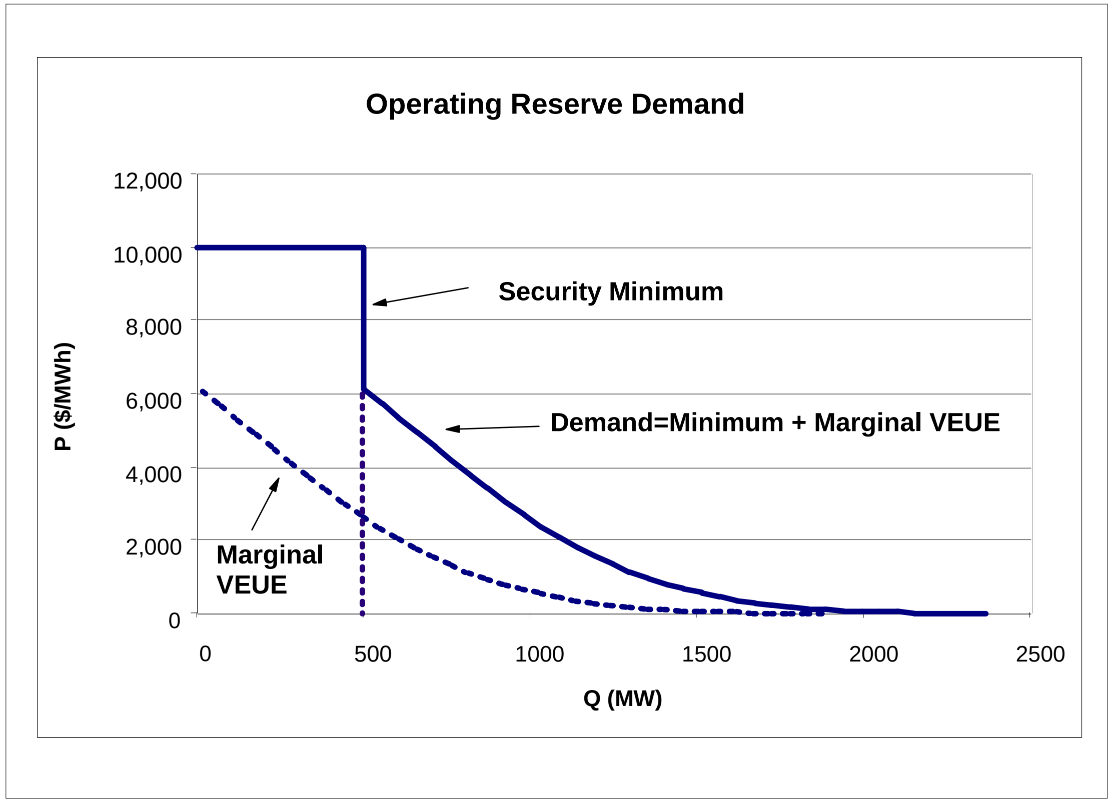


Existing market designs underprice scarcity and provide poor signals for investment. Hence we have the resource adequacy debate. A market would approached would be reinforced by adopting an explicit operating reserve demand curve.

The maximum generation outage contingency quantity provides a vertical demand curve that adds horizontally to a 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.

A realistic operating reserve demand curve would address the missing money problem and help jump start greater demand participation.



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 and ISONE implementations dispose of any argument that it would be impractical to implement an operating reserve demand curve. The only issue is the level of the appropriate price.

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 Locations: Transmission limitations mean that there are locational differences in the need for and efficacy of operating reserves. This would continue to be true with different demand curves for different locations.

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.

Transmission investment presents the most difficult challenges for an electricity market. In practice and in theory, market failures can be significant. If regulatory intervention is required to plan, coordinate and mandate transmission investment, how can the intervention reinforce the larger market design? A focus on market failures provides a framework that might work in theory. Comparison with the Argentine experience suggests the framework would work in practice. Getting this right is important, with implications for the ultimate success of electricity restructuring.

- **Level Playing Field.** A fundamental assumption of electricity restructuring is that market incentives and decentralized decisions would serve better than regulated decisions in determining investment and allocating risk.
  - Get the prices right.
  - Allow the market to determine the balance among investment alternatives.
  - Recognize that transmission is both a complement and a substitute for other investments.
- **Slippery Slopes.** Mandated investments not supported by market signals reveal or create requirements for expanding the scope of central planning and regulatory rather than market decisions.
  - All investments change the economics of all other investments.
  - Mandated investments tend to reinforce the distortions in price signals.
  - The regulatory cure could be worse than the market disease.

An outline of the Argentine experience bears directly on the debate in the United States and elsewhere. (For details, see Stephen C. Littlechild and Carlos J. Skerk, "Regulation of Transmission Expansion in Argentina Part I: State Ownership, Reform and the Fourth Line," CMI EP 61, 2004, pp. 27-28.)

- **Coordinated Spot Market.** Organized under an Independent System Operator with Locational Marginal Pricing.
- **Expansion of Transmission Capacity by Contract Between Parties**. Allowed merchant transmission with voluntary participant funding.
- **Minor Expansions of Transmission Capacity (<$2M)**. Included regulated investment with assignment of cost, either through negotiation or allocation to beneficiaries as determined by regulator, with mandatory participant funding.
- **Major Expansions of Transmission by "Public Contest" Method**. Overcame market failure without overturning markets.
  - Regulator applies the "Golden Rule" (the traditional Cost-Benefit Test).
  - 30%-30% Rule. At least 30% of beneficiaries must be proponents. No more than 30% of beneficiaries can be opponents.
  - Assignment of costs to beneficiaries with mandatory participant funding under "area of influence" methodology.
  - No award of Financial Transmission Rights!
  - Allocation of accumulated congestion rents to reduce cost of construction ("Salex" funds).

What impact did the Argentine approach have on transmission investment?

"To illustrate the change in emphasis on investment, over the period 1993 to 2003 the length of transmission lines increased by 20 per cent, main transformers by 21 per cent, compensators by 27 per cent and substations by 37 per cent, whereas series capacitors increased by 176 per cent. As a result, transmission capacity limits increased by 105 per cent, more than sufficient to meet the increase in system demand of over 50 per cent." (Stephen C. Littlechild and Carlos J. Skerk, "Regulation of Transmission Expansion in Argentina Part II: State Ownership, Reform and the Fourth Line," CMI EP 61, 2004, p. 56.)

Lessons

- **Transmission investment could be compatible with SMD incentives.**
- **Beneficiaries could be defined.**
- **Participant funding could support a market.**
- **Award of FTRs or ARRs would be an obvious enhancement.**

How would the Argentine model translate into the Unites States context?

- **Coordinated Spot Market.** Organized under an Independent System Operator with Locational Marginal Pricing. The Successful Market Design with financial transmission rights.

- **Expansion of Transmission Capacity by Contract Between Parties**. Allow merchant transmission with voluntary participant funding. This is the easy case. Allocate long-term financial transmission rights for the transmission expansion.

- **Minor Expansions of Transmission Capacity (<$2M)**. Includes regulated investment with assignment of cost either through negotiation or assignment to beneficiaries as determined by regulator with mandatory participant funding. Leaves small investments to the initiative of the existing wires companies. Auction incremental FTRs along with FTRs for existing system.

- **Major Expansions of Transmission by "Public Contest" Method**. Overcoming market failure without overturning markets.
    - Regulator applies the "Golden Rule" (Cost-Benefit Test). Use the same economic cost benefit analysis to identify expected beneficiaries.
    - 30%-30% Rule. At least 30% of beneficiaries must be proponents. No more than 30% of beneficiaries can be opponents. This provides an alternative, or a complement, to the "Market Failure Test" to help the regulators limit intervention and support the broader market.
    - Assign costs to beneficiaries with mandatory participant funding.
    - Award either Auction Revenue Rights or long term FTRs to beneficiaries along with costs.

Apply the same general rules to all generation and demand investments that compete with transmission.

- **Coordinated Spot Market.** Organized under an Independent System Operator with Locational Marginal Pricing. The Successful Market Design with financial transmission rights.

- **Voluntary Investment by Contract Between Parties**. Allow merchant generation and demand investment with voluntary participant funding. This is the easy case.

- **Major Investments by "Public Contest" Method**. Overcoming market failure without overturning markets.
  - Regulator applies the "Golden Rule" (Cost-Benefit Test). Use the same economic cost benefit analysis to identify expected beneficiaries.
  - 30%-30% Rule. At least 30% of beneficiaries must be proponents. No more than 30% of beneficiaries can be opponents. Absent a very lumpy investment, the beneficiaries should be a very limited group. Virtually all demand investments and most generation investments would have a single beneficiary.
  - Assign costs to beneficiaries with mandatory participant funding.

In principle, this provides a level playing field while recognizing that there may be market failures that require regulated investments.

Supplemental material

- On design of operating reserve demand curve.
- On minimum uplift pricing.
- On transmission deliverability
- On loop flow

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*):

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

$$s.t.$$

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

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

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

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

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

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

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]

[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 ε^i and possible lost load l^i in at least some conditions.

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

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

Simplify the benefit and cost functions:

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

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.

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

$$s.t.$$

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

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.

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

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

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.

$$\underset{y^0, d^0, g^0, r, u \in \{0,1\}}{Max} B^0\left(d^0\right) - C^0\left(g^0, r, u\right) - VEUE\left(d^0, g^0, r, u\right)$$

$$\begin{aligned}
&s.t.\\
&\quad y^0 = d^0 - g^0,\\
&\quad H^0 y^0 \leq b^0,\\
&\quad g^0 + r \leq u \bullet Cap^0,\\
&\quad \iota^t y^0 = 0,\\
&\quad g^0 \leq u \bullet Cap^0.
\end{aligned}$$

The optimal value of expected unserved energy defines the demand for operating reserves. This formulation of the problem follows the outline of existing operating models except for the exclusion of contingency constraints.

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

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

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*).

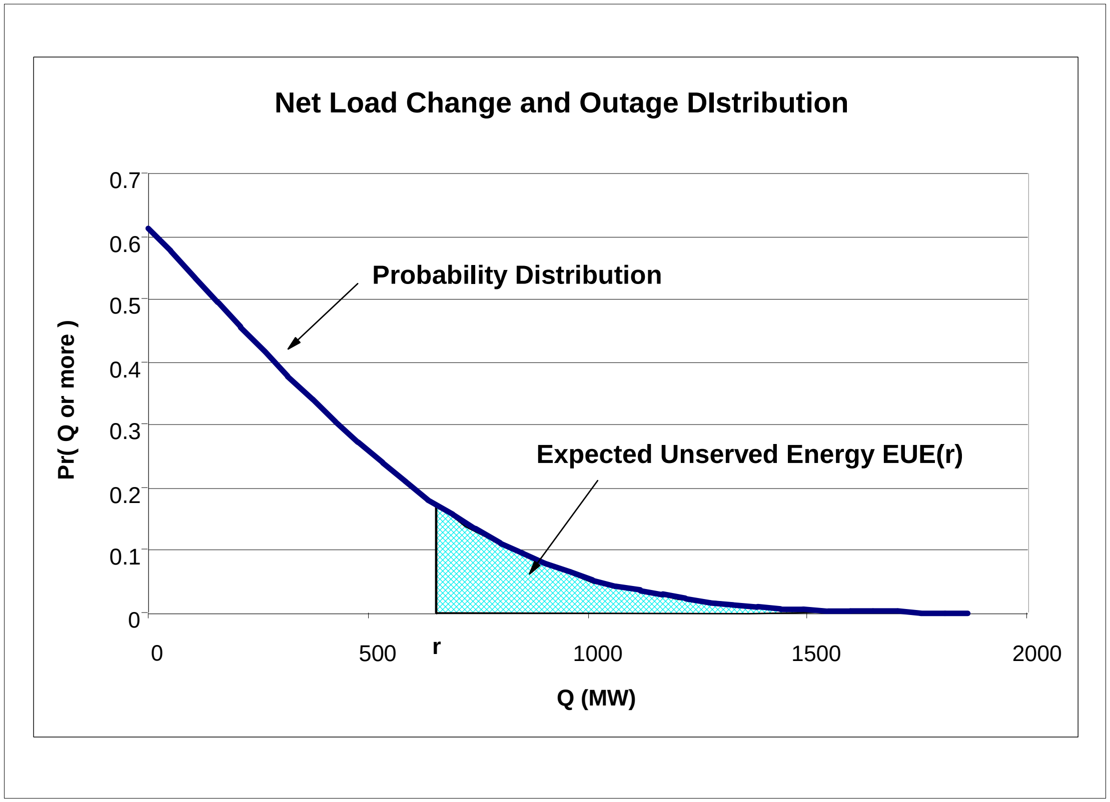
Suppose the *VOLL* per MWh is v. Then we can obtain the *EUE* and its total value (*VEUE*) as:

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

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

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.



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

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

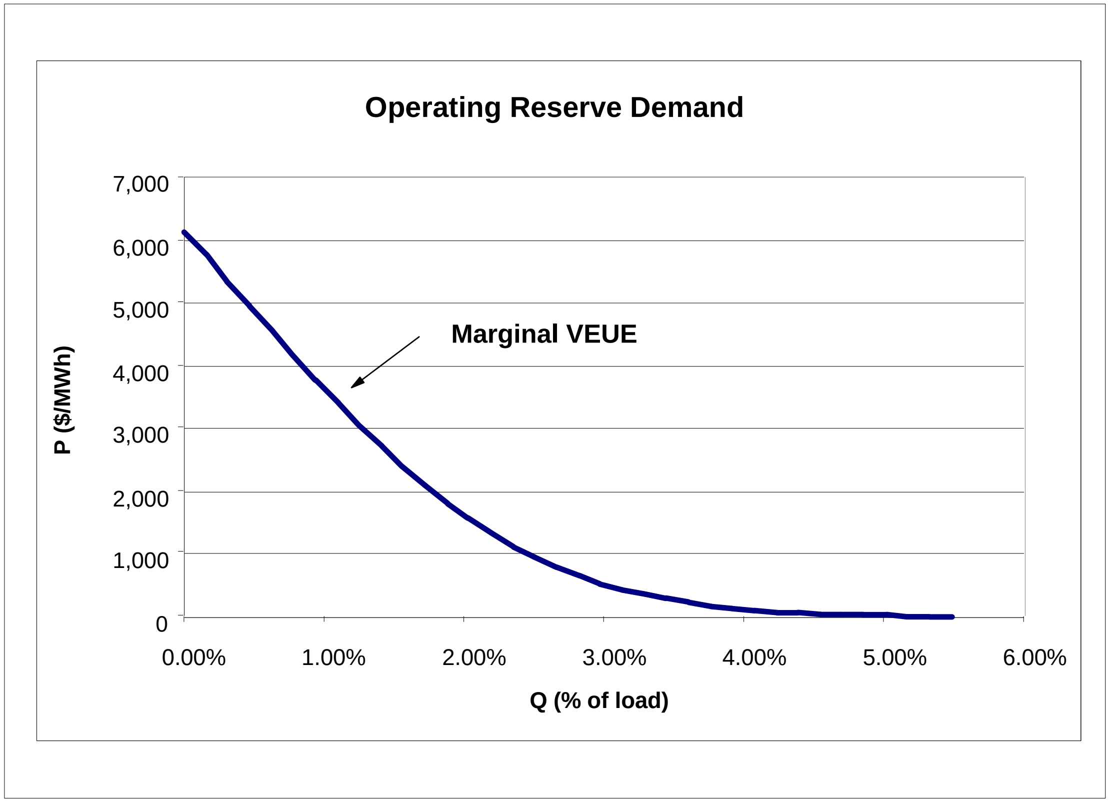
The probabilistic demand for operating reserves reflects the cost and probability of lost load.

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

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. Total value is of same magnitude as the cost of meeting load.



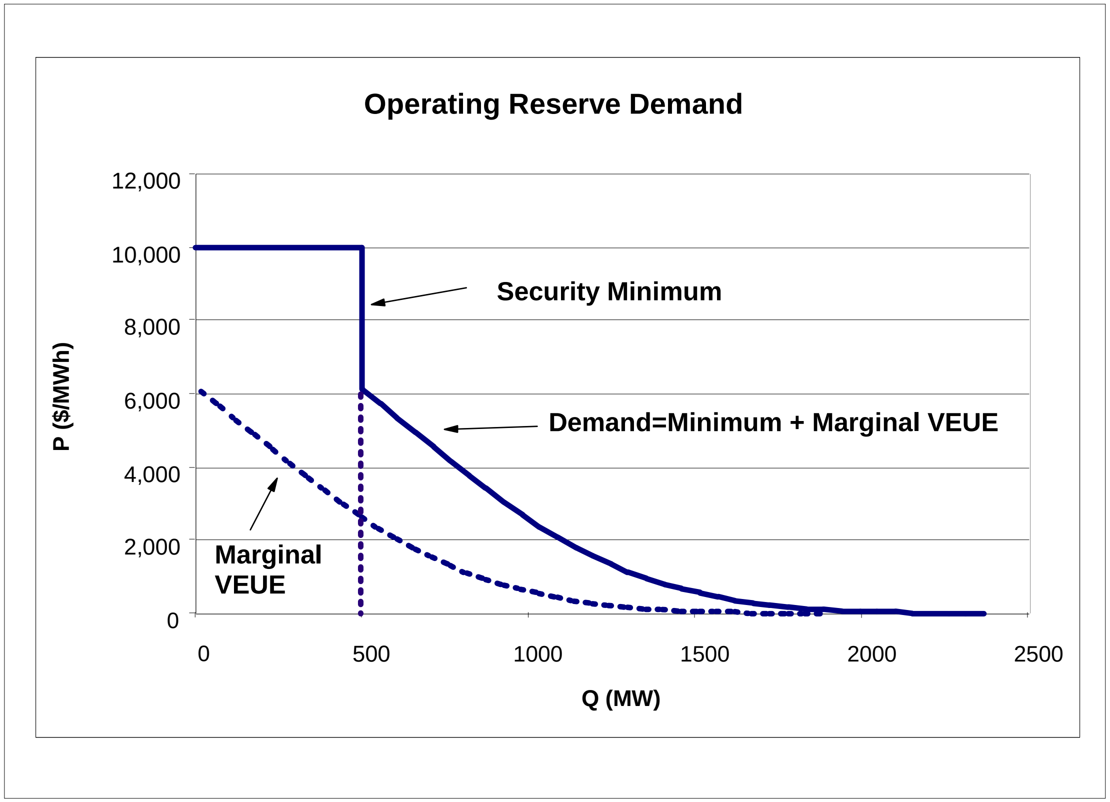
The deterministic approach to security constrained economic dispatch includes lower bounds on the required reserve to ensure that for a set of monitored contingencies (e.g., an n-1 standard) there is sufficient operating reserve to maintain the system for an emergency period.

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.

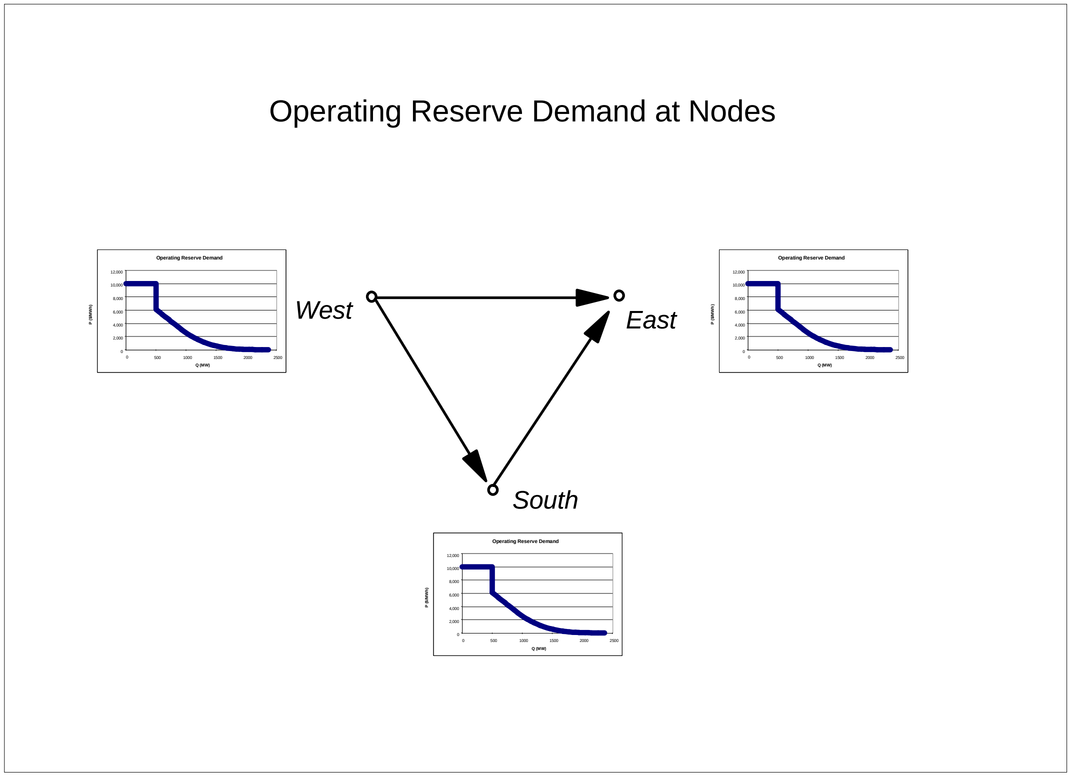
$$H^i y^0 \le \tilde{b}^i, \quad i = 1, 2, \cdots, K_M.$$

The security constrained economic dispatch problem becomes:

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

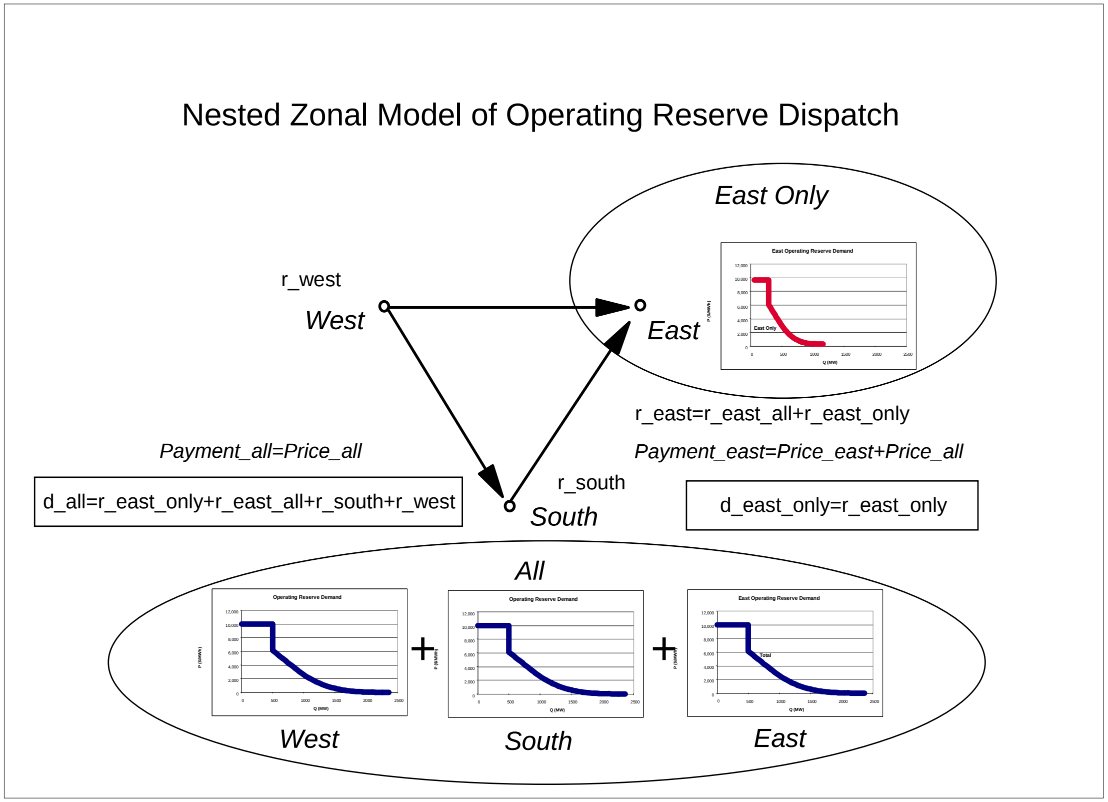
If we could convert each node to look like the single location examined above, the approximation of *VEUE*, would repeat the operating reserve demand curve at each node.

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.



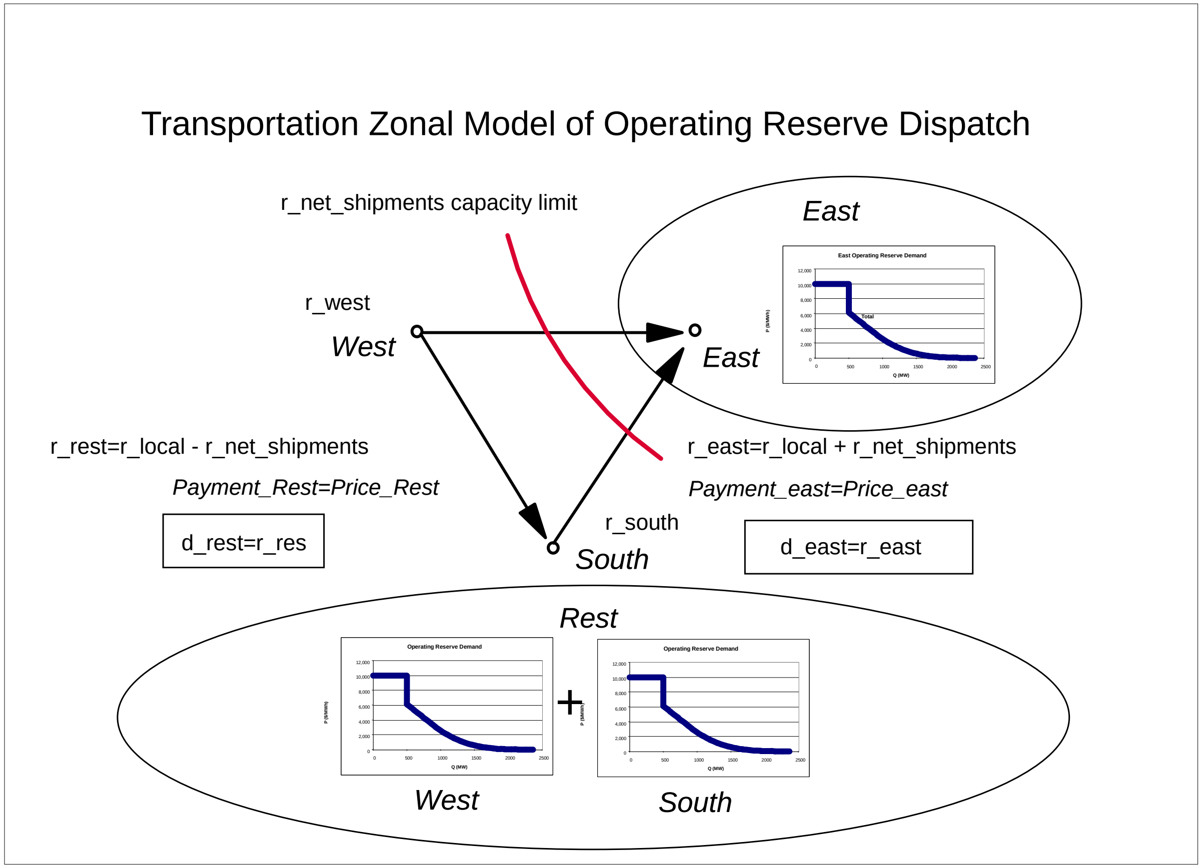
7 Eugene G. Preston, W. Mack Grady, Martin L. Baughman, "A New Planning Model for Assessing the Effects of Transmission Capacity Constraints on the Reliability of Generation Supply for Large Nonequivalenced Electric Networks," IEEE Transactions on Power Systems, Vol. 12, No. 3, August 1997, pp. 1367-1373.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



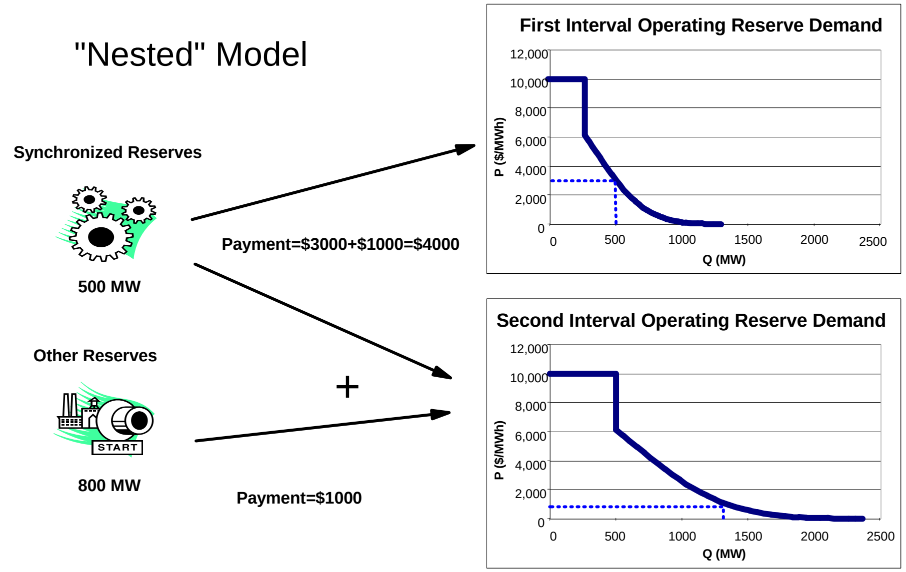
The result is that the input operating reserve price functions are additive premiums that give rise to an implicit operating reserve demand curves with higher prices.

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, but specified an hour ahead rather than years ahead.



Multiple types of operating reserves exist according to response time. A nested model divides the period into consecutive intervals. Reserve schedules set before the period. Uncertainty revealed after the start of the period. Faster responding reserves modeled as available for subsequent intervals. The operating reserve demand curves apply to intervals and the payments to generators include the sum of the prices for the available intervals.

Multiple Operating Reserve Demand Types (Intervals)



Nested model with two intervals, decisions made before uncertainty revealed.

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. 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.
- **Minimum Uplift Pricing.** Dispatch-based pricing that resolves inconsistencies by minimizing the total value of the price discrepancies.
- **…**

Supplemental material

- On design of operating reserve demand curve.
- On minimum uplift pricing.
- On transmission deliverability
- On loop flow.

One-part (LMP) energy pricing provides the idealized framework for a market equilibrium representation of electricity dispatch and the associated prices. The real system can require deviation from one-part energy prices. Practical electricity markets include both approximations and nonconvexities that deviate from the pure case of the simple equilibrium pricing model

- **Nonconvexities:** There may not be a one-part solution that covers the startup and no load costs with multi-part bids and unit commitment.
- **Suboptimal dispatch:** There may be no solution to the market equilibrium conditions if there is less than a perfect dispatch.

The typical pricing solution allows for special side payments, to be included in an uplift charge, to support the market equilibrium conditions.

The “minimum uplift” idea calls for choosing one-part energy and reserve prices to meet the equilibrium conditions while minimizing the side payment contribution to the total uplift charges.

Consider a simple case with four generators having startup costs and constant variable costs.

Plant	Variable Cost C	Capacity q_{max}	Startup Cost S
I	\$20/MWh	25	\$100
II	\$30/MWh	75	\$150
III	\$45/MWh	25	\$100
IV	\$55/MWh	50	\$0

Two locations with low and high demand.

Location	Low Load (MW)	High Load (MW)
A	0	0
B	60	100

Example of uplift components for a problem with economic dispatch and market prices for energy and reserves. The bid and dispatch quantities are taken from the actual dispatch.

Variable Cost Bid	c	Capacity	$q_{\max}$
Startup Cost Bid	S	Undispatched Quantity	q_u
Price of Reserves	p_r	Reserve Quantity	q_r
Price of Energy	p_e	Energy Quantity	q_e

The bids determine the maximum capacity, variable cost and startup costs. The actual dispatch provides the volumes for energy, reserves, and undispatched quantities. The prices are to be determined in order to satisfy the equilibrium conditions of the dispatch.

The equilibrium conditions include the arbitrage conditions among market participants and the optimizing conditions for each participant.

MINIMUM UPLIFT PRICES Example Definitions

Prices determine side payments to cover opportunity costs needed to satisfy the individual equilibrium conditions assuming profit maximization for each producer.

Uplift Categories: Dispatch Opportunity Costs					
		Undispatched	Reserve	Energy	
Undispatched	q_u	0	$p_r q_u$	$\left(p_e - c\right) q_u$	$\leq U_{1u}$
Reserve	q_r	$-p_r q_r$	0	$\left(p_e - c - p_r\right) q_r$	$\leq U_{1r}$
Energy	q_e	$\left(c - p_e\right) q_e$	$\left(p_r + c - p_e\right) q_e$	0	$\leq U_{1e}$

Startup costs not recovered through other payments, and lost opportunity for uncommitted units present other opportunity costs not covered by one-part prices.

Uplift Categories: Startup and Uncommitted Opportunity Costs			
Startup	$S + \left(c - p_e\right) q_e - p_r q_r - \left(U_{1u} + U_{1r} + U_{1e}\right)$		$\leq U_{1S}$
Uncommitted	$\left(p_e - c\right) q_{\max} - S$	$p_r q_{\max} - S$	$\leq U_0$

"Minimum Uplift Pricing" selects prices for energy and reserves to minimize the total side payments across all participants.

$$\underset{p_e^j, p_r^j, \mu, U_{1u}^i, U_{1r}^i, U_{1e}^i, U_{1S}^i, U_0^i \ge 0}{Min} \sum_{i=1}^{n} \left(U_{1u}^i + U_{1r}^i + U_{1e}^i + U_{1S}^i + U_0^i \right)$$

$$
\begin{aligned}
& s.t. \\
& p_e^A + \mu = p_e^B, \\
& U_{1u}^i \ge \left(p_e^{j(i)} - c^i \right) q_u^i, \\
& U_{1u}^i \ge p_r^{j(i)} q_u^i, \\
& U_{1r}^i \ge \left(p_e^{j(i)} - c^i - p_r^{j(i)} \right) q_r^i, \\
& U_{1e}^i \ge \left(c^i - p_e^{j(i)} \right) q_e^i, \\
& U_{1e}^i \ge \left(p_r^{j(i)} - c^i + p_e^{j(i)} \right) q_e^i, \\
& U_{1S}^i \ge S^i + \left(c^i - p_e^{j(i)} \right) q_d^i - p_r^{j(i)} q_r^i - \left(U_{1u}^i + U_{1r}^i + U_{1e}^i \right), \\
& U_0^i \ge \left(p_e^{j(i)} - c^i \right) q_{\max} - S^i, \\
& U_0^i \ge p_r^{j(i)} q_{\max} - S^i; \quad \mathit{for} \quad i = 1, \cdots, n.
\end{aligned}
$$

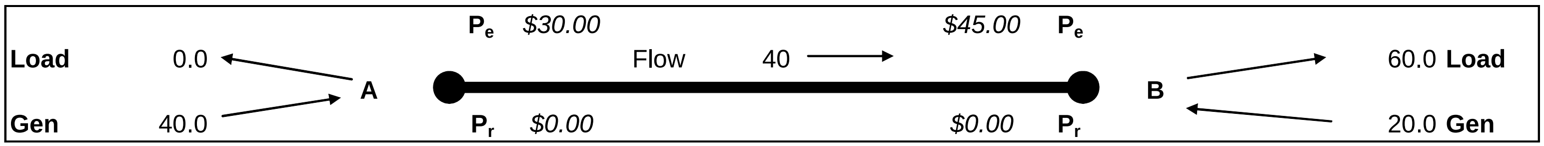
Example with no start up costs, low demand and optimal dispatch. No uplift.

Load at A **0**

Load at B **60**

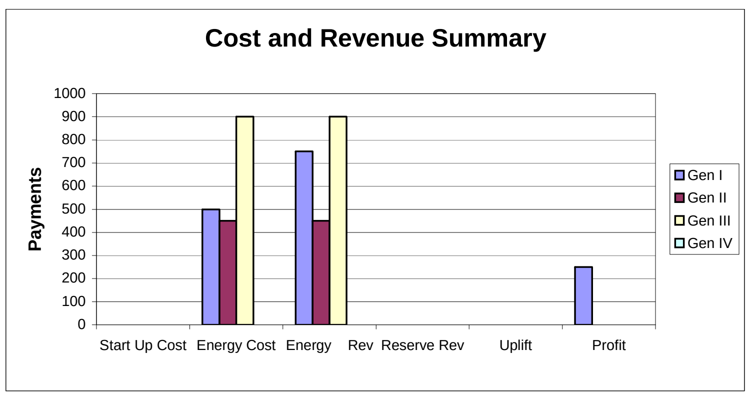
I	Quantity:	Capacity	Production	Reserves	Startup
$20		25.0	25.0	0.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$750	$0	$0	$250

III	Quantity:	Capacity	Production	Reserves	Startup
$45		25.0	20.0	0.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$900	$0	$0	$0



II	Quantity:	Capacity	Production	Reserves	Startup
$30		75.0	15.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$450	$0	$0	$0

IV	Quantity:	Capacity	Production	Reserves	Startup
$55		50.0	0.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$0	$0	$0	$0



MINIMUM UPLIFT PRICES Radial Line

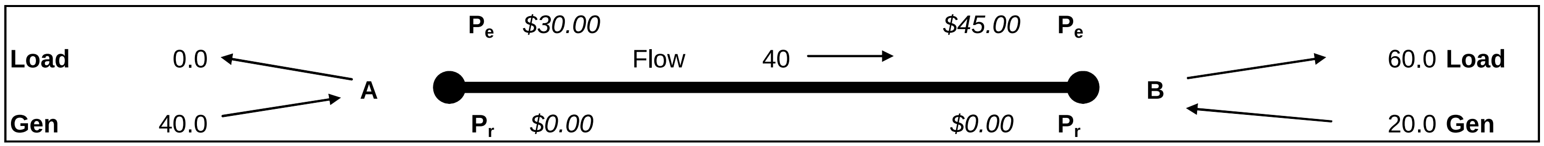
Example with no start up costs, low demand and suboptimal dispatch.

Load at A **0**

Load at B **60**

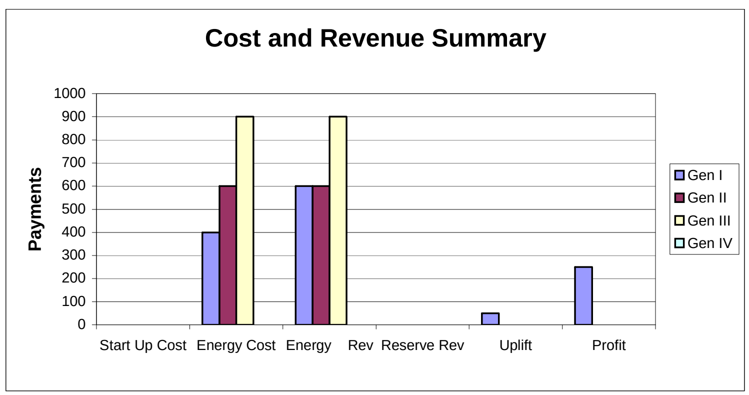
I	Quantity:	Capacity	Production	Reserves	Startup
$20		25.0	20.0	0.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$600	$0	$50	$250

III	Quantity:	Capacity	Production	Reserves	Startup
$45		25.0	20.0	0.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$900	$0	$0	$0



II	Quantity:	Capacity	Production	Reserves	Startup
$30		75.0	20.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$600	$0	$0	$0

IV	Quantity:	Capacity	Production	Reserves	Startup
$55		50.0	0.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$0	$0	$0	$0



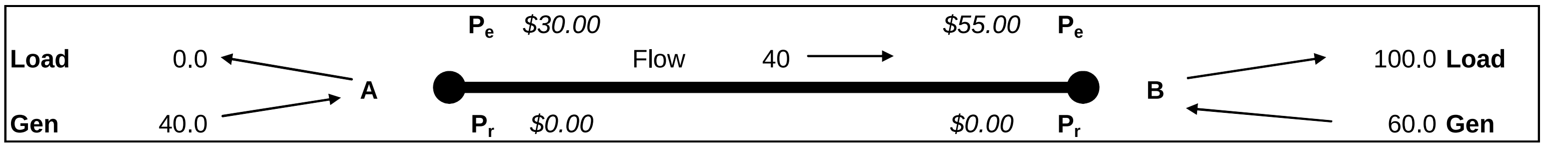
Example with no start up costs, high demand and optimal dispatch. No uplift.

Load at A **0**

Load at B **100**

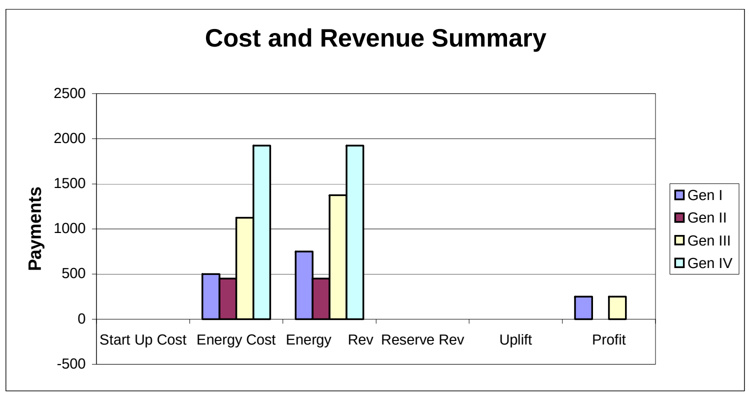
I	Quantity:	Capacity	Production	Reserves	Startup
$20		25.0	25.0	0.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$750	$0	$0	$250

III	Quantity:	Capacity	Production	Reserves	Startup
$45		25.0	25.0	0.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$1,375	$0	$0	$250



II	Quantity:	Capacity	Production	Reserves	Startup
$30		75.0	15.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$450	$0	$0	$0

IV	Quantity:	Capacity	Production	Reserves	Startup
$55		50.0	35.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$1,925	$0	$0	$0

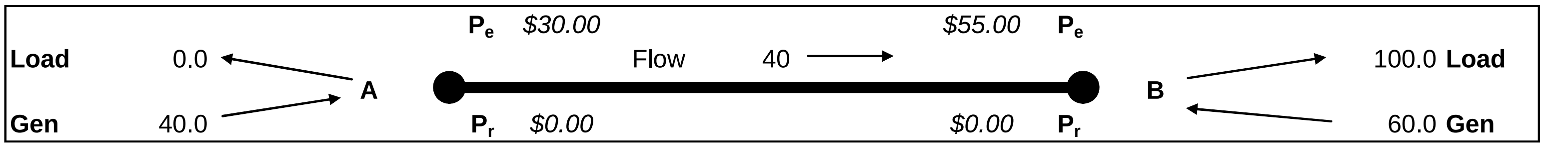


Example with no start up costs, high demand and suboptimal dispatch.

Load at A **0** **Load at B** **100**

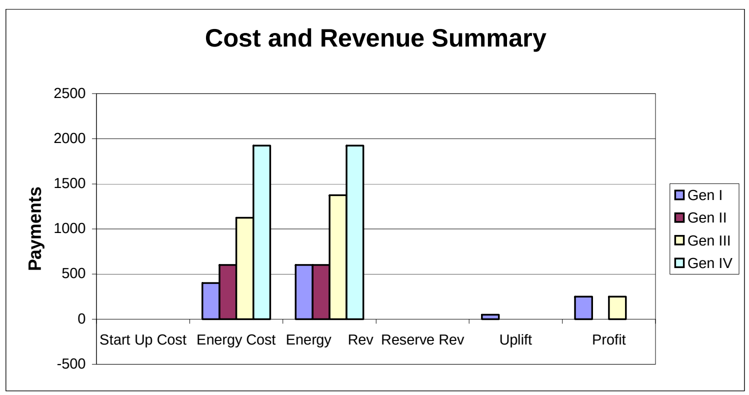
I	Quantity:	Capacity	Production	Reserves	Startup
$20		25.0	20.0	0.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$600	$0	$50	$250

III	Quantity:	Capacity	Production	Reserves	Startup
$45		25.0	25.0	0.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$1,375	$0	$0	$250



II	Quantity:	Capacity	Production	Reserves	Startup
$30		75.0	20.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$600	$0	$0	$0

IV	Quantity:	Capacity	Production	Reserves	Startup
$55		50.0	35.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$1,925	$0	$0	$0



MINIMUM UPLIFT PRICES Radial Line

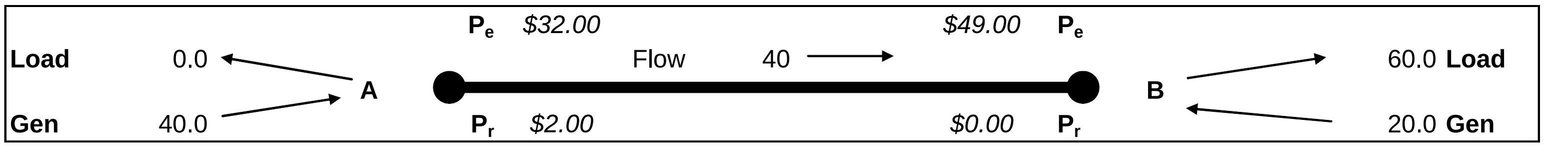
Example with start up costs, low demand and optimal dispatch.

Load at A **0**

Load at B **60**

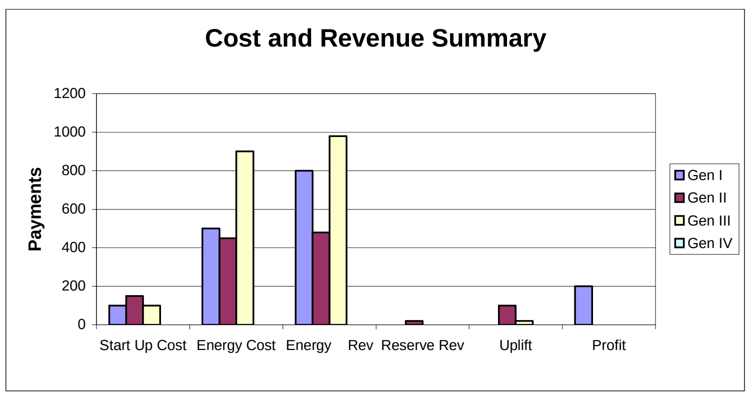
I	Quantity:	Capacity	Production	Reserves	Startup
$20		25.0	25.0	0.0	$100.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$800	$0	$0	$200

III	Quantity:	Capacity	Production	Reserves	Startup
$45		25.0	20.0	0.0	$100.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$980	$0	$20	$0



II	Quantity:	Capacity	Production	Reserves	Startup
$30		75.0	15.0	10.0	$150.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$480	$20	$100	$0

IV	Quantity:	Capacity	Production	Reserves	Startup
$55		50.0	0.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$0	$0	$0	$0



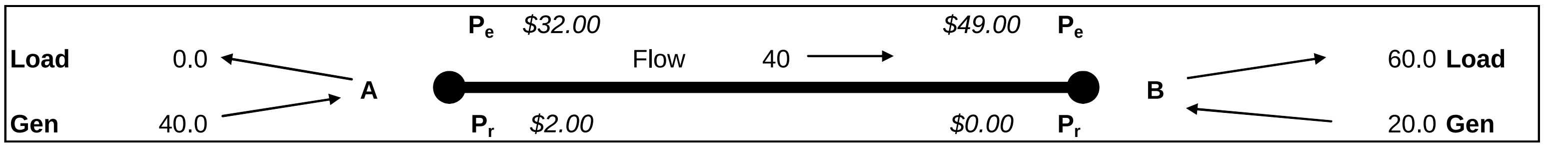
Example with start up costs, low demand and suboptimal dispatch.

Load at A **0**

Load at B **60**

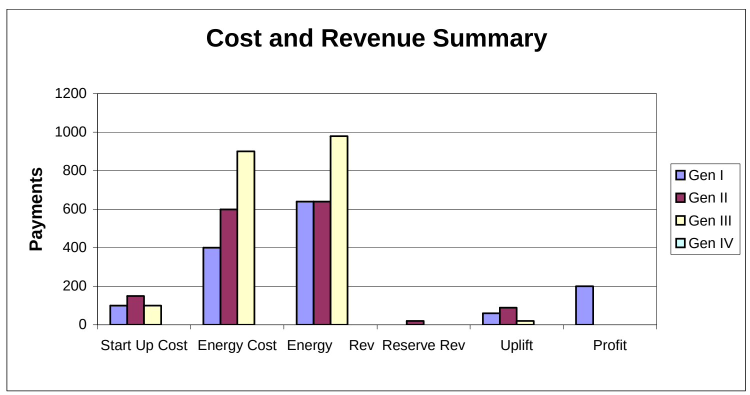
I	Quantity:	Capacity	Production	Reserves	Startup
$20		25.0	20.0	0.0	$100.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$640	$0	$60	$200

III	Quantity:	Capacity	Production	Reserves	Startup
$45		25.0	20.0	0.0	$100.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$980	$0	$20	$0



II	Quantity:	Capacity	Production	Reserves	Startup
$30		75.0	20.0	10.0	$150.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$640	$20	$90	$0

IV	Quantity:	Capacity	Production	Reserves	Startup
$55		50.0	0.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$0	$0	$0	$0



MINIMUM UPLIFT PRICES — Radial Line

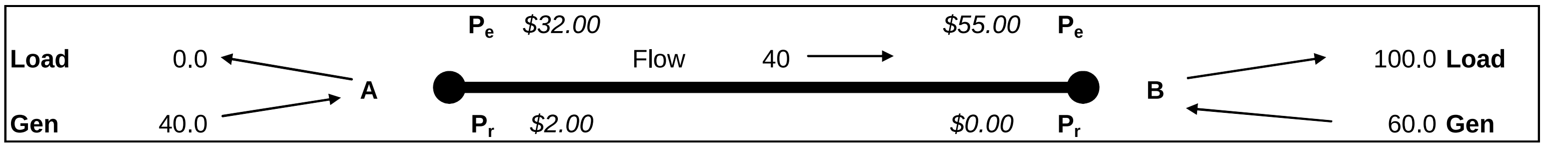
Example with start up costs, high demand and optimal dispatch.

Load at A **0**

I	Quantity:	Capacity	Production	Reserves	Startup
$20		25.0	25.0	0.0	$100.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$800	$0	$0	$200

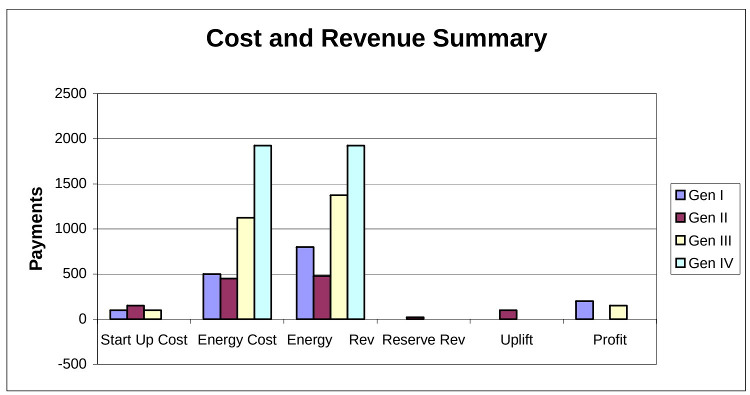
Load at B **100**

III	Quantity:	Capacity	Production	Reserves	Startup
$45		25.0	25.0	0.0	$100.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$1,375	$0	$0	$150



II	Quantity:	Capacity	Production	Reserves	Startup
$30		75.0	15.0	10.0	$150.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$480	$20	$100	$0

IV	Quantity:	Capacity	Production	Reserves	Startup
$55		50.0	35.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$1,925	$0	$0	$0



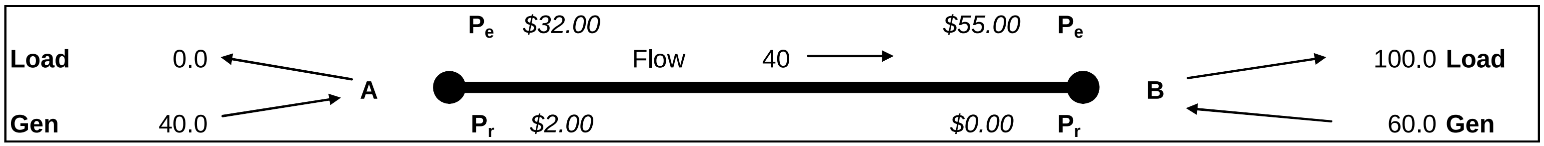
MINIMUM UPLIFT PRICES

Example with start up costs, high demand and suboptimal dispatch.

Load at A **0** **Load at B** **100**

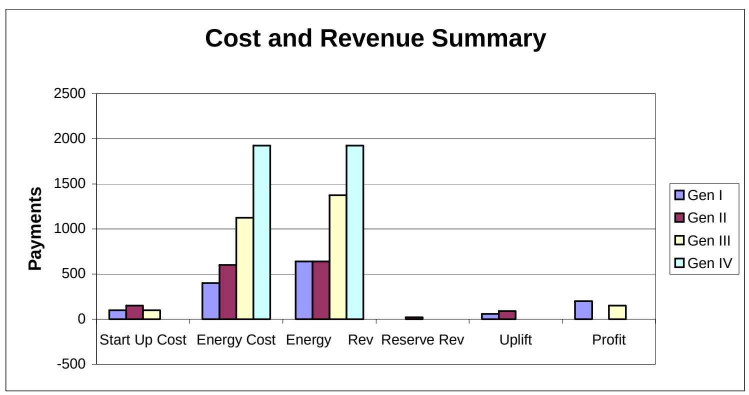
I	Quantity:	Capacity	Production	Reserves	Startup
$20		25.0	20.0	0.0	$100.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$640	$0	$60	$200

III	Quantity:	Capacity	Production	Reserves	Startup
$45		25.0	25.0	0.0	$100.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$1,375	$0	$0	$150



II	Quantity:	Capacity	Production	Reserves	Startup
$30		75.0	20.0	10.0	$150.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$640	$20	$90	$0

IV	Quantity:	Capacity	Production	Reserves	Startup
$55		50.0	35.0	10.0	$0.0
	Revenue:	Energy	Reserve	Uplift	Profit
		$1,925	$0	$0	$0



The paper "On Minimum Uplift Pricing,"[8] examined the difference between pure incremental pricing and pricing to minimize side payments contributing to uplift.

Let:

$B_{it}\left(d_{it}\right)$	Bid-based, well-behaved concave benefit function of demand for customer i in period t.
$C_{jt}\left(g_{jt}\right)$	Bid-based, well-behaved convex cost function for output of generator j in period t.
S_j	Bid-based startup cost for generator j.
m_j, M_j	Bid-based minimum and maximum output for generator j if committed.
z_j	Integer variable ($z_j = 0,1$) modeling commitment decision for generator j.
y_t	Vector of net load at each location, $y_{\varphi t} = \sum_{i \in \varphi} d_{it} - \sum_{j \in \varphi} g_{jt}$, for location φ.
$L_t\left(y_t\right)$	Losses in period t, with net demand $\iota^t y_t$, where $\iota^t = \left(1 \quad 1 \quad \cdots \quad 1\right)$.
$K_t\left(y_t\right)$	Transmission constraints for net load y_t in period t.
$R_{jt}\left(g_{jt}, g_{jt-1}\right)$	Ramping or other dynamic limits for generator j.

Then the stylized economic unit commitment and economic dispatch problem considered here is:

---

[8] 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) .

Economic Unit Commitment and Economic Dispatch.

$$\underset{d_{it}, g_{jt}, y_t, z_j}{Max} \sum_{t=1}^{T} \left(\sum_i B_{it}\left(d_{it}\right) - \sum_j C_{jt}\left(g_{jt}\right) \right) - \sum_j S_j z_j$$

$$s.t.$$

$$L_t\left(y_t\right) + \iota^t y_t = 0,$$

$$y_t = d_t - g_t, \forall t,$$

$$g_{jt} \geq z_j m_j, \forall jt,$$

$$g_{jt} \leq z_j M_j, \forall jt,$$

$$R_{jt}\left(g_{jt}, g_{jt-1}\right) \leq 0, \forall jt,$$

$$K_t\left(y_t\right) \leq 0, \forall t,$$

$$z_j = 0 \; or \; 1, \forall j.$$

Simplified Economic Unit Commitment and Least Cost Dispatch.

$$\underset{g_j, z_j}{Min} \sum_j C_j\left(g_{jt}\right) + \sum_j S_j z_j$$

$$s.t.$$

$$\sum_j g_j = d,$$

$$g_j \geq z_j m_j, \forall j,$$

$$g_j \leq z_j M_j, \forall j,$$

$$z_j = 0 \, or \, 1, \forall j.$$

The formulation of "uplift" side payments for the adapted Scarf example.

$$\tilde{\pi}_j(p) = Max\left(0, \Pi_j^+ - \Pi_j^*\right),$$

$$where$$

$$\Pi_j^* = pg_j^* - C_j\left(g_j^*\right) - S_j z_j^*,$$

$$\Pi_j^+ = \underset{g_j, z_j}{Max}\; pg_j - C_j\left(g_j\right) - S_j z_j$$

$$s.t.$$

$$g_j \geq z_j m_j,$$

$$g_j \leq z_j M_j,$$

$$z_j = 0 \; or \; 1.$$

The objective is to choose the prices to minimize the total uplift contribution:

$$\sum_j \tilde{\pi}_j(p).$$

The adapted Scarf example illustrates the possible difference between "pure incremental cost" prices and minimum uplift prices.

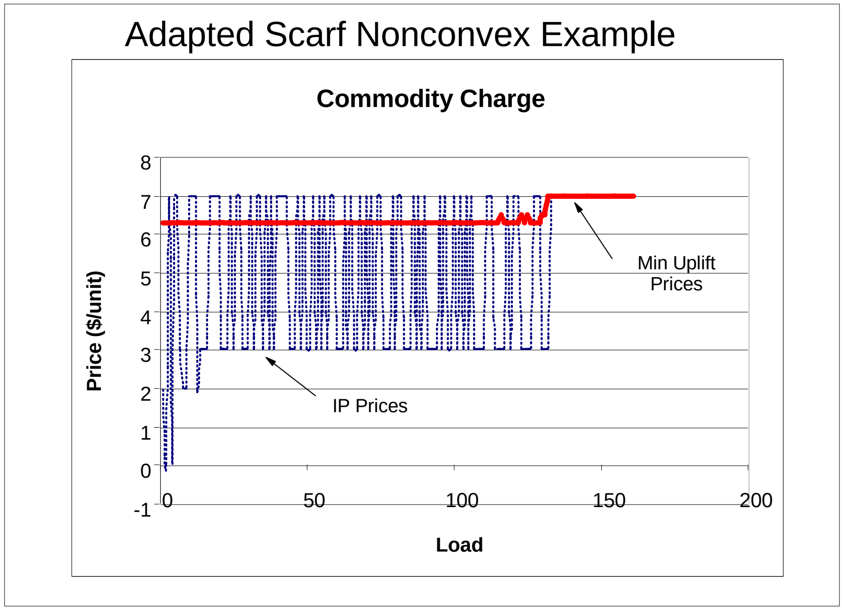
Production Characteristics

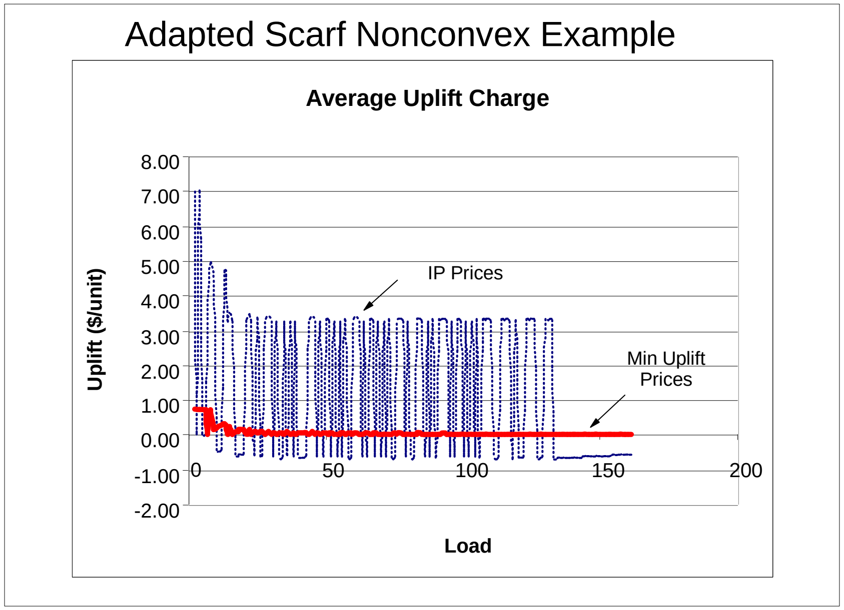
	Smokestack	High Tech	Med Tech
Capacity	16	7	6
Minimum Output	0	0	2
Startup Cost	53	30	0
Marginal Cost	3	2	7
Average Cost at Capacity	6.3125	6.2857	7

The "pure incremental cost" approach determines energy prices according to marginal cost and the other side payments to meet the equilibrium conditions.

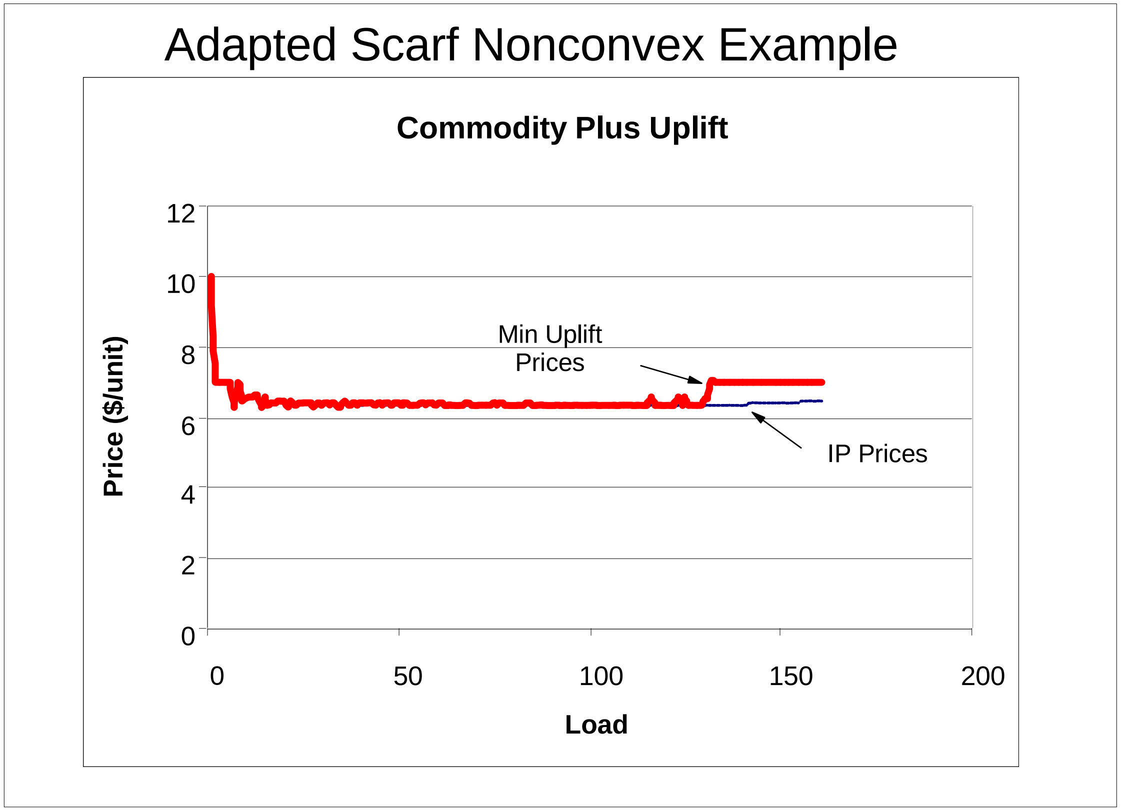
The "minimum uplift" solution picks the prices and uplift side payments to the generators in order to minimize the total of such uplift payments subject to the equilibrium conditions.

The Scarf example illustrates the possible difference between "pure" incremental prices and minimum uplift prices.

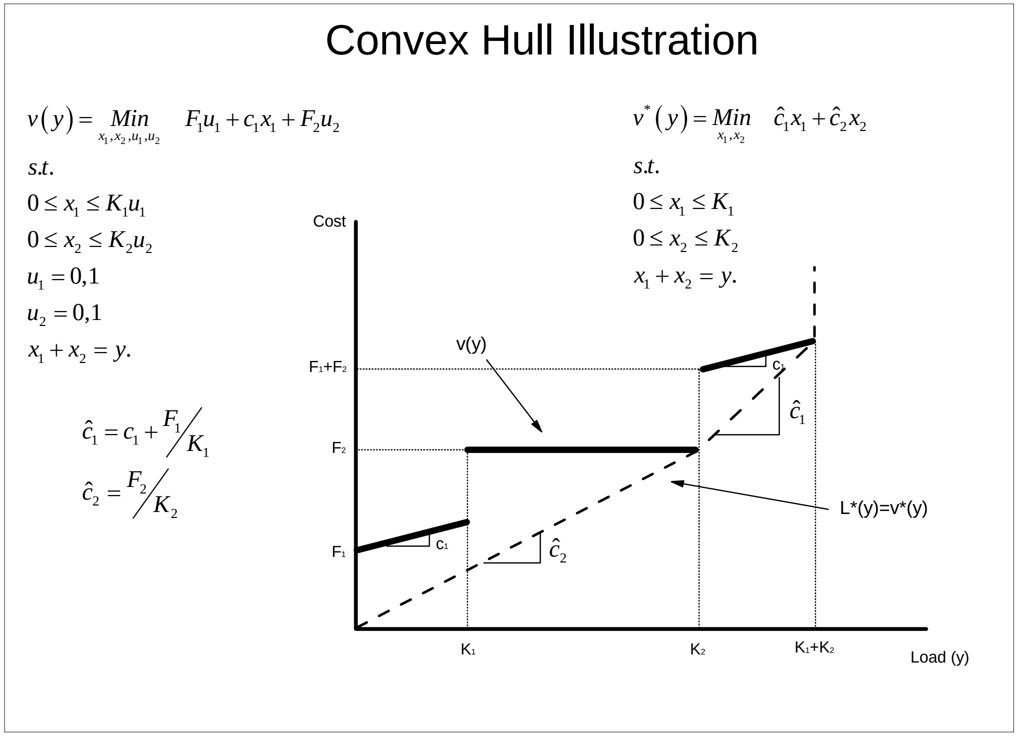




The Scarf example illustrates the possible difference between "pure" incremental prices and minimum uplift prices.



The minimum uplift prices have an interpretation as the prices implied by the convex hull $\left(v^*(y)\right)$ of the economic commitment and dispatch $\left(v(y)\right)$, as well as the price solution for the dual for a standard Lagrangian relaxation formulation $\left(L^*(y)\right)$.[9]



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9 Paul R. Gribik, William W. Hogan, and Susan L. Pope, "Market-Clearing Electricity Prices and Energy Uplift," December 2007, (available at www.whogan.com).

The simple examples illustrate the basic principles. The simple examples have been extended with similar results to address:

- Network representation
- Demand bids
- Multiple periods

The next steps would be to develop examples with extensions to include:

- Operating Reserves
- Security Constraints
- Day ahead and real time interactions
- Other?

Supplemental material

- **On design of operating reserve demand curve.**
- **On minimum uplift pricing.**
- **On transmission deliverability.**
- **On loop flow.**

Planning standards call for generation capacity deliverability. This reliability venue raises again the problematic determination of the total transfer capability (TTC) of the transmission system.

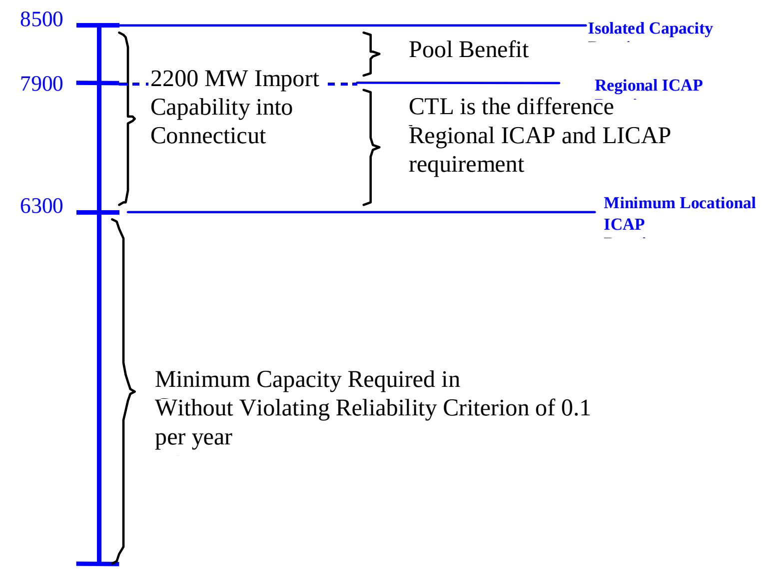
> "The Transfer Capability between two areas is typically assessed or determined by modeling a generation excess in the "from" area at a specific source point(s) and a generation deficiency in the "to" area at a specific sink point(s). The increased source level at which the loading on a transmission element is at its normal rating (with no contingencies) or its emergency rating (with an outage of a generation unit or a transmission element) is be defined as the incremental Transfer Capability.
>
> Selection of the specific source and sink points will impact the calculated 'power transfer distribution factors' and various transmission facility loadings to determine the AFC/ATC values and to determine the anticipated impact of a Transmission Service Request on specific Flowgates. Therefore, the posted AFC/ATC, as well as the evaluation of a transmission service request, is greatly influenced by the selection of these points. Transmission service sold based on a set of source/sink points that do not correspond to the generation that moves for the schedule results in inaccurate ATC values."
>
> (NERC, "Long-Term AFC/ATC Task Force Final Report," Revised April 14, 2005, Appendix B, p. 1)

Many applications of the interface TTC in multi-zone reliability calculations are treated as transportation models in the contract path mode. In other words, the loop effects are ignored and the power transfer distribution factors are dropped. The subsequent reliability simulations compute "capacity" dispatch and flows for loss of load calculations as though the contact path model applied.

(For example, see New York State Reliability Council, "New York Control Area Installed Capacity Requirements For The Period May 2005 Through April 2006," L.L.C. Executive Committee Resolution And Technical Study Report, December 10, 2004, p. 32.)

For reliability purposes the ISONE definition of transmission deliverability transfer limits applies a transportation interface but is not the same as the transmission contract path.

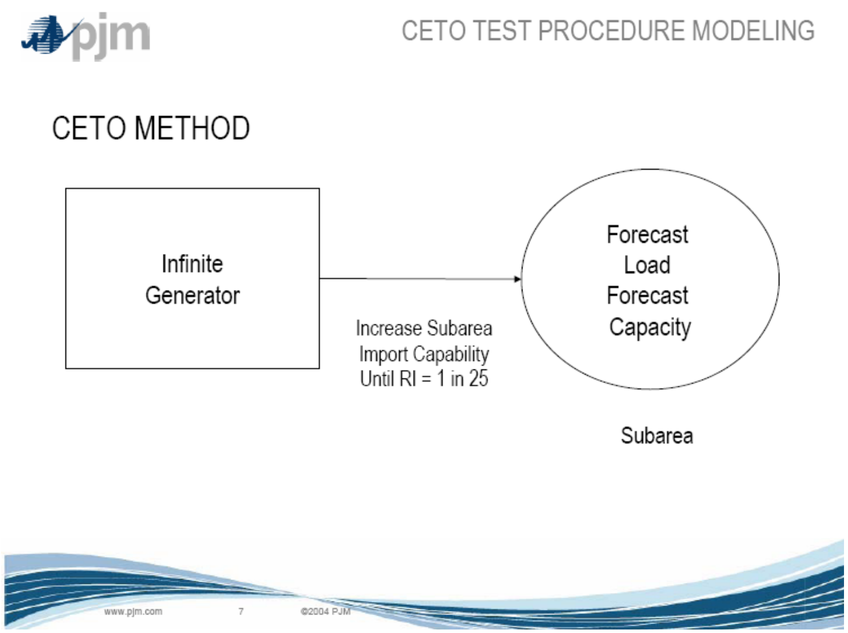
Relationship of Physical Transfer Limit to
Pool Benefit and Capacity Transfer Limit
State of Connecticut (Estimated)

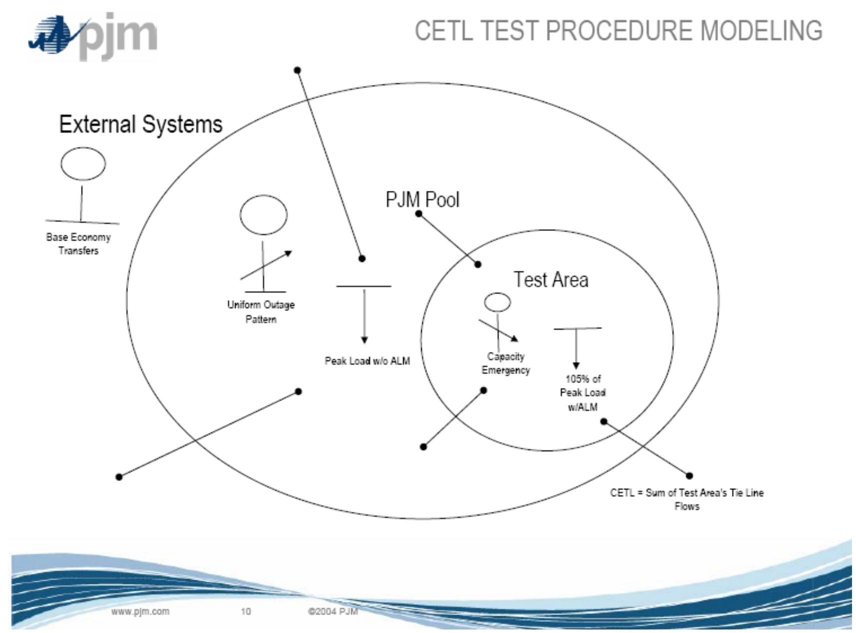


Defining the target zone as a single region, with no transmission import capability, the sequential Monte Carlo simulation estimates the isolated LOLP assuming zero transmission imports. This leads to the 8500 MW "Isolated Capacity" requirement to meet the 1/10 standard. Then apply a two zone model with the target zone and the rest of ISONE. Sequentially remove generation from the target zone until the ISONE LOLP reduces to the 1/10 standard. The resulting capacity in the target zone is the "local sourcing requirement," the 6300 MW that defines the "Minimum Locational ICAP." Separately, there is an allocation of the total ISONE ICAP that is the "Regional ICAP" that becomes the target zone's regional requirement. The 1600 MW Capacity Transfer Limit (CTL) is the difference between the regional requirement and the minimum as a result of the decrementing rule.

(Hogan summary of "Prepared Direct Testimony of David LaPlante on Behalf Of ISO New England Inc.," Docket No. ER03-563-030, August 31, 2004, p.35.)

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.)

The differences between ISONE and PJM deliverability definitions reflect an underlying problem in establishing long term planning standards. Comparison with the challenge of long term transmission rights illustrates the difficulty.

> "Selection of the specific source and sink points will impact the calculated 'power transfer distribution factors' and various transmission facility loadings to determine the AFC/ATC values and to determine the anticipated impact of a Transmission Service Request on specific Flowgates. Therefore, the posted AFC/ATC, as well as the evaluation of a transmission service request, is greatly influenced by the selection of these points. Transmission service sold based on a set of source/sink points that do not correspond to the generation that moves for the schedule results in inaccurate ATC values."
>
> (NERC, "Long-Term AFC/ATC Task Force Final Report," Revised April 14, 2005, Appendix B, p. 1)

Since "deliverability" depends very much on how the system would be used, reliability planning standards make conservative assumptions to allow simplified calculations like the two zone transportation models with a single interface. This problem is difficult. If we need long term planning standards, there may be no other workable approach.

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.

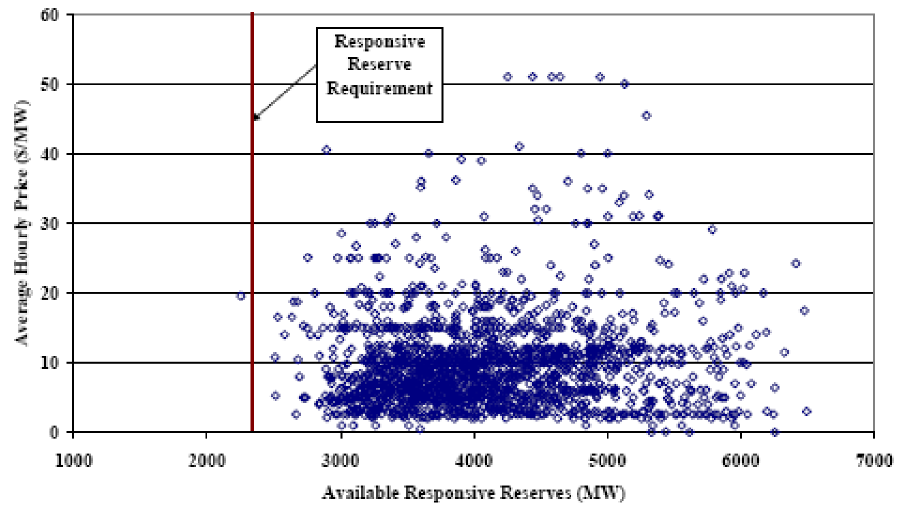
c) The Northern Illinois Spinning Reserve Zone Requirement is defined as 50% of ComEd's load ratio share of the largest system contingency within MAIN.

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.

Figure 22: Hourly Responsive Reserves Capability vs. Market Clearing Price Afternoon Peak Hours – 2004



"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).

The call for intervention to assure generation investment commitments interacts with the mandatory investments in transmission under the central plan.

" … recent generation retirements have highlighted a fundamental problem with the long-term planning of the transmission system. The load deliverability analysis performed in the RTEP process requires as input the generation resources that will be available to support delivery of imported energy to load. Uncertainty in the generation resource availability for future years creates a significant amount of uncertainty in the future regional transmission plan. Since reliability is a fundamental requirement, this planning uncertainty cannot be sustained. To correct this problem, the PJM region needs to return to a longer-term forward capacity obligation to commit generation for future years. A four-year forward commitment period is needed for generation capacity obligations to ensure that the five-year PJM RTEP has adequate forward information on generation conditions, so that proper planning and coordination of transmission upgrades can be assured." (Andrew L. Ott, "Affidavit of Andrew l. Ott on Behalf Of PJM Interconnection, L.L.C.," PJM RPM Proposal, August 31, 2005, p. 12.)

Supplemental material

- On design of operating reserve demand curve.
- On minimum uplift pricing.
- On transmission deliverability.
- On loop flow.

Under Order 888 the FERC made a crucial choice regarding a central complication of the electricity system.

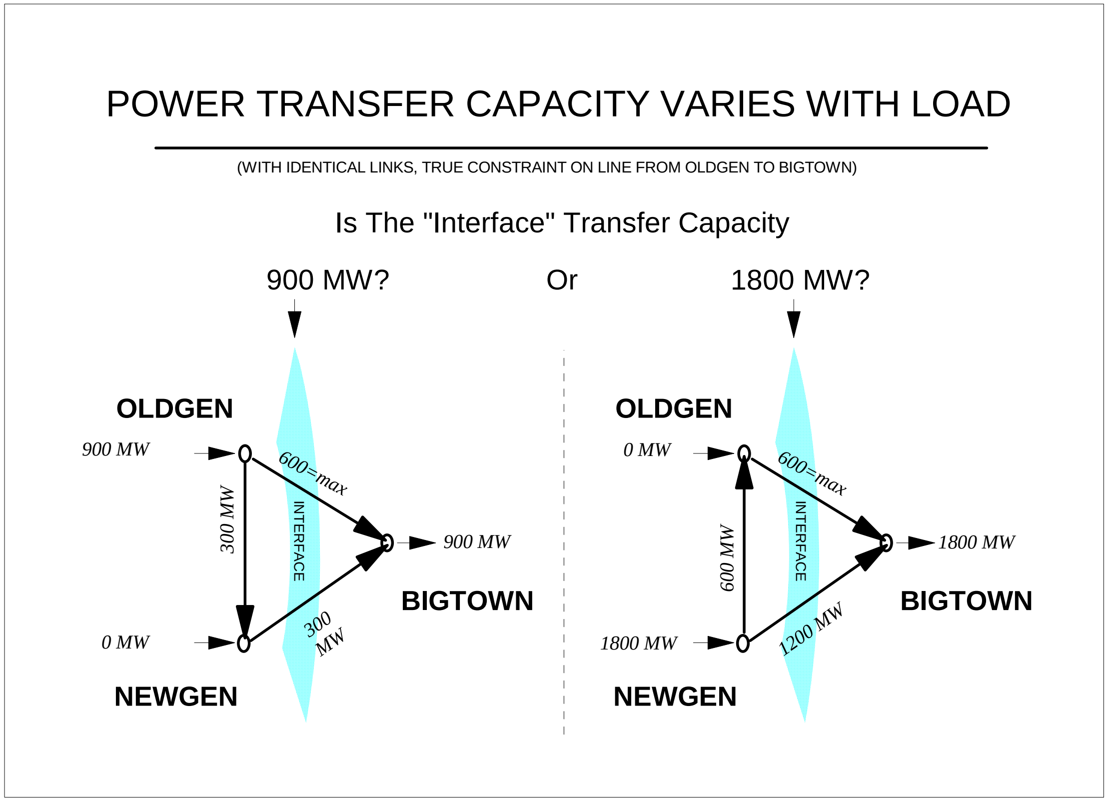
> "A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. … Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the "unscheduled flows" that occur under a contract path regime." (FERC, Order 888, April 24, 1996, footnotes 184-185, p. 93.)

Why is this important? A quick tutorial follows.

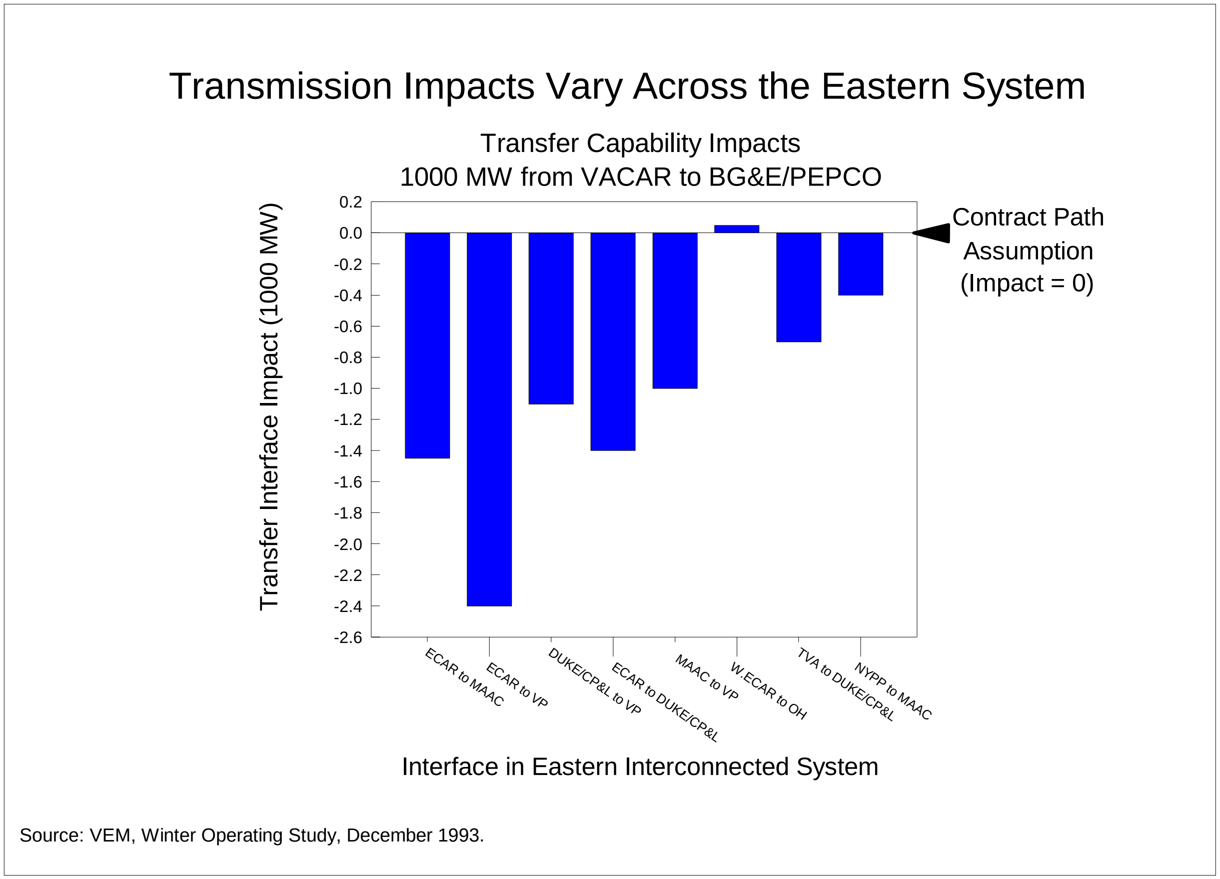
Electric transmission network interactions can be large and important.

- Conventional definitions of network "Interface" transfer capacity depend on the assumed load conditions.

- Transfer capacity cannot be defined or guaranteed over any reasonable horizon.



There is a fatal flaw in the old "contract path" model of power moving between locations along a designated path. The network effects are strong. Power flows across one "interface" can have a dramatic effect on the capacity of other, distant interfaces.



TRANSMISSION CAPACITY — Definition

Electricity restructuring requires open access to the transmission essential facility. A fully decentralized competitive market would benefit from tradable property rights in the transmission grid. However, the industry has never been able to define workable transmission property rights:

> "A primary purpose of the RIN is for users to learn what Available Transmission Capacity (ATC) may be available for their use. Because of effects of ongoing and changing transactions, changes in system conditions, loop flows, unforeseen outages, etc., ATC is not capable of precise determination or definition. "
>
> Comments of the Members of the PJM Interconnection, Request for Comments Regarding Real-Time Information Networks, Docket No. RM95-9-000, FERC, July 5, 1995, p. 8.

The problems are not unique to the U. S. They same issue arises in any meshed network, as in Europe and the regulations for European Transmission System Operators [ETSO]:

> "Does the draft Regulation set the right objective when it requires TSOs to compute and publish transfer capacities? ETSO says both yes and no …in many cases the (Net transfer capacity or NTCs) may be a somewhat ambiguous information…The core of the difficulty raised by transfer capacities lies in the fact that they do not obey usual arithmetic: 'it makes no sense to add or subtract the NTC values…' Put it in other ways, in order to compute the maximal use of the network, one needs to make assumptions on the use of the network! This definition is restated and elaborated in ETSO (2001a) (p. 6)."
>
> J. Boucher and Y. Smeers, "Towards a Common European Electricity Market--Paths in the Right Direction…Still Far From an Effective Design," Belgium. September, 2001, pp. 30-31. (see HEPG web page, Harvard University)

Under Order 888 the FERC made a crucial choice regarding a central complication of the electricity system.

> "A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. … Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the "unscheduled flows" that occur under a contract path regime." (FERC, Order 888, April 24, 1996, footnotes 184-185, p. 93.)

> "We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. In reaching this conclusion, we recognize that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment, as described by Hogan and others. At the same time, however, contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. To require now a dramatic overhaul of the traditional approach such as a shift to some form of flow-based pricing and contracting could severely slow, if not derail for some time, the move to open access and more competitive wholesale bulk power markets. In addition, we believe it is premature for the Commission to impose generically a new pricing regime without the benefit of any experience with such pricing. We welcome new and innovative proposals, but we will not impose them in this Rule." (FERC, Order 888, April 24, 1996, p. 96.)

Hence, although the fictional contract path approach would not work in theory, maintaining the fiction would be less disruptive in moving quickly to open access and an expanded competitive market!

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, 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).