ELECTRICITY RESOURCE ADEQUACY:
RELIABILITY, SCARCITY, AND
OPERATING RESERVE DEMAND CURVES

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ELECTRICITY MARKET

Overcoming Market Failure

In the case of wholesale electricity markets, the choice between a pure market and central administrative solutions is a false dichotomy.

- With current technology and system configuration, central administrative interventions are necessary.
  - Limited control and metering.
  - Balancing, Dispatch and Security constraints.

- Not all administrative interventions are equivalent.
  - Vicious circles.
    Zonal pricing ➤ constrained-on and -off payments ➤ misplaced investment ➤ integrated resource procurements ➤ the ISO as the “utilities’ utility.”
  - Virtuous circles.
    Nodal pricing ➤ bid-based, security-constrained economic dispatch ➤ financial transmission rights.
Incomplete scarcity pricing leaves “missing money.” This creates poor operational and investment incentives. There is a need for administrative intervention.

- **Installed Capacity.** Assuming it is impossible to provide adequate scarcity pricing, interventions focus on installed capacity requirements.
  
  o Emphasis on physical capacity and planning targets. This seems natural and innocuous, but the physical perspective leads to a host of market design problems.
  
  o Requirement for longer-term regulatory commitments and decisions. Substantial payments must come through the regulatory decision, investment requires the commitment.
  
  o Assumes there is some method for defining and ensuring transmission deliverability. If we knew how to do this, everything would be easier. But the electricity network makes this difficult.
  
  o Experience reveals unintended consequences and renews interest in better scarcity pricing.

- **Scarcity Pricing.** Suspending disbelief, consider better scarcity pricing.
  
  o An “energy only” market without an installed capacity requirement, but with alternative regulatory requirements.
  
  o Or “belts and suspenders” with better scarcity pricing that supports an installed capacity system.
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.
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.”

ELECTRICITY MARKET

Reliability Standards

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

<table>
<thead>
<tr>
<th>Concept</th>
<th>Search Result</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economic</td>
<td>“For emergency, not economic, reasons.” (Attachment 1-EOP-002-0)</td>
</tr>
<tr>
<td>Cost</td>
<td>“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)</td>
</tr>
<tr>
<td>Price</td>
<td>NA</td>
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<td>Tariff Rate</td>
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This suggests there is a long way to go in constructing mutual reinforcement between market designs and reliability standards.

Where to begin?¹

The solution to open access and non-discrimination inherently involves market design. Good design begins with the real-time market, and works backward. A common failure mode starts with the forward market, without specifying the rules and prices that would apply in real time.

Market expectations determine incentives. Start at the end. Work backward, not forward, in setting market design.

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)
The usual discussion of reliability planning standards refers to the loss of load probability (LOLP) and the ubiquitous 1 day in 10 years standard.

“Loss of Load Expectation (LOLE) — LOLE is the expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand (load). The LOLE is usually measured in days/year or hours/year. The convention is that when given in days/year, it represents a comparison between daily peak values and available generation. When given in hours/year, it represents a comparison of hourly load to available generation. LOLE is sometimes referred to as loss of load probability (LOLP), where LOLP is the proportion (probability) of days per year, hours per year, or events per season that available generating capacity/energy is insufficient to serve the daily peak or hourly demand. This analysis is generally performed for several years into the future and the typical standard metric is the loss of load probability of one day in ten years or 0.1 day/year.”


Ideally we would have consistent application where:

\[
LOLE = LOLP \times \text{PERIOD} = \frac{1 \text{ day}}{10 \text{ yrs}} \times 0.1 \frac{\text{day}}{\text{year}} \times 10 \text{ years} = 1 \text{ day} = 24 \text{ hours} = 2.4 \text{ hrs/yr.}
\]

This is not the same as “events.” With a modeled event of 2.4 hrs, 0.1 day/year implies 2.4 hrs/decade.
Despite the common reference to the 1 in 10 standard, there is not much standardization of reliability planning standards. This may not be much of a problem, but the same terms mean different things in different places.

“Because utilities have historically planned generation reliability such that the expected number of days in a year with inadequate generation to meet load is well under one day, LOLP is typically expressed as 1-day-in-X-years; for example 1-day-in-10-years or 1-day-in-20-years. Note that “1-day-in-10-years” in this case does not mean that there is an expectation of 24 hours of outages in ten years. Rather, the metric indicates that there is a 1 in 10 chance that during the year there will be an outage during one of the 365 days.”


Other criteria include Expected Unserved Energy (EUE) and Value of Service (VOS).

**Modeling for planning standards includes a range of approaches.**

- Deterministic
- Probabilistic
  - Independent
  - Sequential

The many assumptions produce different reserve margin requirements, but the differences in definitions are small compared to the gap between the formulation of reliability standards and market design.
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.

Optimal Duration ≈ \[ \frac{\text{Peaker Fixed Charge}}{\text{Value Lost Load}} \]

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.

**Implied Average Value of Lost Load**

- Twenty Four Hours in Ten Years

**Optimal Duration** ≈ Peaker Fixed Charge Value Lost Load

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

Reliability Standards

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

Implied prices differ by orders of magnitude. (Price Cap $≈10^3$; VOLL $≈10^4$; Reliability Standard $≈10^5$)
ELECTRICITY MARKET  Generation Resource Adequacy

A variety of market rules for spot markets interact to create *de jure* or *de facto* price caps. The resulting “missing money” reduces payments to all types of generation. The reduced payments affect operating and investment incentives for demand, generation and transmission.

If market prices do not provide adequate incentives for generation investment, the result is a market failure. The market design defect creates the pressure for regulators to intervene to mandate generation investment.
ELECTRICITY MARKET

The obvious solution was to create a regulatory requirement that load serving entities purchase sufficient installed generation capacity to meet the projected load plus an adequate reserve margin.

- Installed Capacity (ICAP) requirements through short-tem auctions or deficiency charges. A regulatory requirement to obtain “capacity” for peak load plus a reserve margin.
  - PJM daily requirement.
  - NYISO monthly requirement.
  - ISONE monthly requirement.

- The apparently obvious solution has not worked. ICAP is seen as a failed model. But it won’t go away. Reforms of these reforms followed with further interventions.
  - Locational variant (LICAP) in NYISO with local installed reserve demand curve.
  - Peaking Unit Safe Harbor (PUSH) model for controlled exercise of market power in ISONE.
  - Reliability Must Run (RMR) and Out of Market (OOM) purchases, everywhere.

FERC recognizes the growing pressure for RMR contracts and similar interventions as part of the problem, not the solution.
The latest reforms of resource adequacy reforms move substantially in the direction of greater prescription and mandates from the central planners.

- **ISONE LICAP Proposal (August 31, 2004). FCM Settlement Proposal (March 6, 2006).**
  - LICAP: Locational Demand Curve. FCM: Fixed demand with pricing restrictions.
  - Zonal Transfer Limits.
  - LICAP: Month-Ahead Requirements. FCM: Three-year-Ahead Requirements.
  - Rules for Demand, Generation and Transmission Tradeoffs.

- **PJM Reliability Pricing Model (RPM) Proposal (August 31, 2005).**
  - Locational Variable Resource Requirement (VRR).
  - Zonal Transfer Limits.
  - Four-year-Ahead Requirements.
  - Rules for Demand, Generation and Transmission Tradeoffs.

Both proposals face substantial opposition over jurisdictional, cost and complexity issues.

However, given the defects in the electricity market designs, the direction established in these proposals is natural and inevitable. Given the assumptions, many of the elements of the proposals are logical and sophisticated. But the programs are unlikely to be enough to meet the objectives. And not all the pieces fit, or are even yet defined. More prescriptions will follow.
ELECTRICITY MARKET  Generation Resource Adequacy

Given the expanding prescriptions of generation resources adequacy programs built on installed capacity requirements, there is a greater willingness to step back and look at the assumptions.

- Focus on the market failure.
  - Missing money arises from *de facto* price caps.
  - A market-based resource adequacy program would not slide down the slippery slope.

- An energy only market alternative with no installed capacity mandate.
  - Texas White Paper and PUC Staff proposal. (July 2005).
  - MISO White Paper and Staff proposal (August 2005).

- An “energy only” market alternative with compatible interventions.
  - Target operating conditions rather than planning standards.
  - Create a workable electricity spot market without the missing money.
  - Design other compatible interventions with hedging and market power mitigation to address the problems that motivated the *de facto* price caps.
  - Think “market based” rather than “command and control.”
A workable “energy only” market would eliminate the “missing money” problem and provide an alternative to the growing prescriptions of installed capacity markets. The concept is not that there should be no market interventions. But the interventions should not overturn the market.

An “Energy Only” Market Outline

- Implicit demand for inflexible load would define the opportunity costs as the average value of lost load (VOLL).

Involuntary curtailment of inflexible demand has an opportunity cost at the average value of lost load (VOLL).
An “Energy Only” Market Outline

- Operating reserve demand curve would reflect capacity scarcity.

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 sensitive.
... An “Energy Only” Market Outline

- Market clearing eliminates the “missing money.”

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<tr>
<td>Q(MW)</td>
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<tr>
<td>P ($/MWh)</td>
<td>P ($/MWh)</td>
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<tr>
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<td>$10,000</td>
</tr>
<tr>
<td>$30</td>
<td>$7,000</td>
</tr>
</tbody>
</table>

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

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

Generation Resource Adequacy

... An “Energy Only” Market Outline

- The average VOLL becomes the *de facto* price cap. But it is not a price cap that limits bids or leads to out of market purchases.

![Average VOLL is "Energy Only" Price Cap](image)

Prices do not rise above the average VOLL unless *all* inflexible demand is subject to involuntary curtailment.
ELECTRICITY MARKET Generation Resource Adequacy

... An “Energy Only” Market Outline

- Energy only market issues.
  - **Electricity Network Effects.** Can this work in a network?
  - **Demand Response.** How can there be scarcity pricing without a demand response?
  - **Reliability.** What is the impact on reliability?
  - **Missing Markets.** How do we deal with other ancillary services?
  - **Market Power.** What would be required to mitigate market power?
  - **Inadequate Contracting.** How can the market for investment work without adequate contracting?
“Energy only” market outline.

- **Electricity Network Effects.** Can this work in a network?

  Most of the design is conventional. The operating reserve demand curve can be included in the network in the same way as operating reserve requirements (e.g., NYISO).

- **Demand Response.** How can there be scarcity pricing without a demand response?

  More demand response would be better, but the analysis applies to whatever demand response exists, and the operating reserve demand curve ensures some price response. The resulting scarcity pricing provides incentives for more demand response.

- **Reliability.** What is the impact on reliability?

  The loss of load probability is evaluated in real time. The resulting average may be more or less than the planning standard. However, the generic planning standard is largely disconnected from markets and forecasting abilities. Where there is no alternative, the planning standard approach looks appealing. But with better scarcity pricing focused on the real reliability problem in real time, the planning standard is difficult to justify.
• “Energy only” market outline.

  o **Missing Markets.** How do we deal with other ancillary services?

    Voltage support, reactive power, black start and so on, would remain as issues requiring attention to assure adequate and efficient supply. However, improved scarcity pricing for energy and operating reserves should not make these problems more difficult, and might make them easier.

  o **Market Power.** What would be required to mitigate market power?

    Hedging contracts would help, but are unlikely to be sufficient. Market power mitigation through offer caps is consistent with the design, assuming the mitigation implementation allows for scarcity pricing when operating reserves are scarce.
“Energy only” market outline.

- **Inadequate Contracting.** How can the market for investment work without adequate contracting?

Without forward hedges, regulators are unlikely to accept scarcity pricing. And investors are unlikely to believe regulators won’t intervene if high prices appear. Market participants may not enter into enough forward hedges to create counterparties for forward contracts that could support capacity investment. Accepting these reasons, some intervention is required.

- A compatible intervention would be some form of mandatory load hedging (MLH).

  - Hedges required for default load.
  - Utilize financial contracts for energy at the load location.
  - No explicit connection to “physical” capacity or transmission deliverability.
  - Certification limited to credit requirements.
  - E.g.: New Jersey Basic Generation Service (BGS) auction.
  - Liquidated damages contracts are part of the solution, not part of the problem.
  - Intermediaries would extend the forward contract horizon.
  - Forward contracts would support infrastructure investment.
ELECTRICITY MARKET Summary

... An “Energy Only” Market Outline Summary

- “Energy only” market outline.
  - Address “missing money” problem through scarcity pricing.
  - Mitigate market power through offer caps.
  - Hedge with mandatory financial contracts for energy at the load location.
  - Avoid most or all RMR and OOM requirements.
  - Avoid central mandates for generation capacity, demand and transmission tradeoffs.
  - Remove perverse incentives for operations during critical scarcity periods.
  - Use existing performance monitoring for settlements and operating reserves.
  - Avoid special rules restricting electricity market access during scarcity conditions.

- “Belts and suspenders” insurance.
  - Better scarcity pricing makes an installed capacity system easier and less important.
  - Operating incentives cover everything, not just capacity accepted in a forward auction.
ELECTRICITY MARKET Operating Reserve

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.\(^2\)

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 \((\text{Cap})\), reserves \((r)\), commitment decisions \((u)\), transmission constraints \((H)\), and state probabilities \((p)\):

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

s.t.

\[
y^i = d^i - g^i, \quad i = 0, 1, 2, \ldots, N,
\]

\[
i^i y^i = 0, \quad i = 0, 1, 2, \ldots, N,
\]

\[
H^i y^i \leq b^i, \quad i = 0, 1, 2, \ldots, N,
\]

\[
g^0 + r \leq u \cdot \text{Cap}^0,
\]

\[
g^i \leq g^0 + r, \quad i = 1, 2, \ldots, N,
\]

\[
g^i \leq u \cdot \text{Cap}^i, \quad i = 0, 1, 2, \ldots, N.
\]

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.\(^3\)

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ELECTRICITY MARKET

Operating Reserve

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

\[
\begin{align*}
\text{Max} & \quad p_0 \left( B^0 \left( d^0 \right) - C^0 \left( g^0, r, u \right) \right) + \sum_{i=1}^{N} p_i \left( B^i \left( d^0 + \varepsilon^i - l^i, d^0 \right) - C^i \left( g^i, g^0, r, u \right) \right) \\
\text{s.t.} & \quad y^0 = d^0 - g^0, \\
& \quad y^i = d^0 + \varepsilon^i - g^i - l^i, \quad i = 1, 2, \ldots, N, \\
& \quad i' i' = 0, \quad i = 0, 1, 2, \ldots, N, \\
& \quad H^i y^i \leq b^i, \quad i = 0, 1, 2, \ldots, N, \\
& \quad g^0 + r \leq u \cdot \text{Cap}^0, \\
& \quad g^i \leq g^0 + r, \quad i = 1, 2, \ldots, N, \\
& \quad g^i \leq u \cdot \text{Cap}^i, \quad i = 0, 1, 2, \ldots, N.
\end{align*}
\]

Simplify the benefit and cost functions:

\[
\begin{align*}
B^i \left( d^0 + \varepsilon^i - l^i, d^0 \right) & \approx B^0 \left( d^0 \right) + k^i_d - v^i l^i, \quad C^i \left( g^i, g^0, r, u \right) \approx C^0 \left( g^0, r, u \right) + k^i_g.
\end{align*}
\]

This produces an approximate objective function:

\[
\begin{align*}
p_0 \left( B^0 \left( d^0 \right) - C^0 \left( g^0, r, u \right) \right) + \sum_{i=1}^{N} p_i \left( B^i \left( d^0 - l^i, d^0 \right) - C^i \left( g^i, g^0, r, u \right) \right) = B^0 \left( d^0 \right) - C^0 \left( g^0, r, u \right) + \sum_{i=1}^{N} p_i \left( k^i_d - k^i_g \right) - v^i \sum_{i=1}^{N} p_i l^i.
\end{align*}
\]
The revised formulation highlights the pre-contingency objective function and the role of the value of the expected undeserved energy.

\[
\text{Max}_{y^0, d^0, g^0, r, u \in [0, 1]} \quad B^0(d^0) - C^0(g^0, r, u) - \nu \sum_{i=1}^{N} p_i l^i
\]

s.t.
\[
\begin{align*}
y^0 &= d^0 - g^0, \\
y^i &= d^0 + e^i - g^i - l^i, \quad i = 1, 2, \ldots, N, \\
l^i \cdot y^i &= 0, \quad i = 0, 1, 2, \ldots, N, \\
H^i y^i &= b^i, \quad i = 0, 1, 2, \ldots, N, \\
g^0 + r &\leq u \cdot \text{Cap}^0, \\
g^i &\leq g^0 + r, \quad i = 1, 2, \ldots, N, \\
g^i &\leq u \cdot \text{Cap}^i, \quad i = 0, 1, 2, \ldots, N.
\end{align*}
\]

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.

\[
VEUE(d^0, g^0, r, u) = \min_{y^i, d^i, g^i, r} \sum_{i=1}^{N} p_i l^i
\]

s.t.
\[
y^i = d^0 + \epsilon^i - g^i - l^i, \quad i = 1, 2, \cdots, N,
\]
\[
i^i y^i = 0, \quad i = 1, 2, \cdots, N,
\]
\[
H^i y^i \leq b^i, \quad i = 1, 2, \cdots, N,
\]
\[
g^0 + r \leq u \cdot Cap^0,
\]
\[
g^i \leq g^0 + r, \quad i = 1, 2, \cdots, N,
\]
\[
g^i \leq u \cdot Cap^i, \quad i = 1, 2, \cdots, N.
\]

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.

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

s.t.

$$y^0 = d^0 - g^0,$$
$$H^0 y^0 \leq b^0,$$
$$g^0 + r \leq u \cdot \text{Cap}^0,$$
$$i^t y^0 = 0,$$
$$g^0 \leq u \cdot \text{Cap}^0.$$
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.

\[
\text{Unserved Energy} = \text{Max}(0, \text{Load} - \text{Available Capacity})
\]

Hence

\[
\text{Unserved Energy} = \text{Max}(0, E(\text{Load}) + \Delta \text{Load} - (\text{Committed Capacity} - \Delta \text{Capacity}))
\]

\[
= \text{Max}(0, \Delta \text{Load} + \text{Outage} + (E(\text{Load}) - \text{Committed Capacity})
\]

\[
= \text{Max}(0, \Delta \text{Load} + \text{Outage} - \text{Operating Reserve}).
\]

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 \((r)\),

\[
\text{LOLP} = \Pr(\Delta \text{Load} + \text{Outage} \geq r) = F_{\text{LOLP}}(r).
\]

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

\[
F_{\text{LOLP}}(r) \leq \text{LOLP}_{\text{Max}}.
\]

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:

\[
EUE(r) = \int_r^\infty F_{LOL} (x) \, dx.
\]

\[
VEUE(r) = v \int_r^\infty F_{LOL} (x) \, dx.
\]

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

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: \( \Delta \text{Load} \sim N\left(0, \sigma_L^2\right) \).

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 \( \omega_j \), typically a small value on the order of less than \( 10^{-2} \):

\[
\text{Outage} = \sum_j u_j \text{Cap}_j o_j,
\]

\[
\Pr(o_j = 1 | u_j = 1) = \omega_j.
\]

A common approximation of \( \Pr(\text{Outage}) \) is a mixture of distributions with a positive probability of no outage and a conditional distribution of outages that follows an exponential distribution:

\[
\Pr(\text{Outage} = 0) = p_0, \quad \Pr(\text{Outage} > x) = (1 - p_0) e^{-\lambda x}.
\]

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

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

\[ \text{Outage} \sim N\left(\mu_O, \sigma_O^2\right). \]

Then with operating reserves \( r \), the distribution of the lost load is

\[ \text{LOLP} = \Pr\left(\Delta \text{ Load} + \text{Outage} \geq r\right) = \overline{F_{\text{LOL}}}\left(r\right) \]
\[ = \Phi\left(r \mid \mu_O, \sigma_O^2 + \sigma_L^2\right) = 1 - \Phi\left(r \mid \mu_O, \sigma_O^2 + \sigma_L^2\right). \]

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

\[ EUE\left(r\right) = \int_{r}^{\infty} \Phi\left(x \mid \mu_O, \sigma_O^2 + \sigma_L^2\right) dx. \]
\[ VEUE\left(r\right) = v \int_{r}^{\infty} \Phi\left(x \mid \mu_O, \sigma_O^2 + \sigma_L^2\right) dx. \]

This gives the implied reserve inverse demand curve as

\[ \text{Operating Reserve Demand Price}\left(r\right) = P_{OR}\left(r\right) = v\Phi\left(r \mid \mu_O, \sigma_O^2 + \sigma_L^2\right). \]
The probabilistic demand for operating reserves reflects the cost and probability of lost load.

\[ \text{Operating Reserve Demand Price} (r) = P_{OR} (r) = \sqrt{\Phi \left( r \bigg| \mu_O, \sigma_O^2 + \sigma_L^2 \right)} \]  

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.
ELECTRICITY MARKET

Operating Reserve Demand

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 \( r_{\text{Min}}(d^0, g^0, u) \). Then we would have the constraint:
\[
    r \geq r_{\text{Min}}(d^0, g^0, u).
\]

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.

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

The security constrained economic dispatch problem becomes:

$$\begin{align*}
\text{Max} & \quad B^0 \left( d^0 \right) - C^0 \left( g^0, r, u \right) - \text{VEUE} \left( d^0, g^0, r, u \right) \\
\text{s.t.} & \quad y^0 = d^0 - g^0, \\
& \quad H^0 y^0 \leq b^0, \\
& \quad H^i y^0 \leq \tilde{b}^i, \quad i = 1, 2, \ldots, K_M, \\
& \quad g^0 + r \leq u \cdot \text{Cap}^0, \\
& \quad r \geq r_{\min} \left( d^0, g^0, u \right) \\
& \quad i^i y^0 = 0, \\
& \quad g^0 \leq u \cdot \text{Cap}^0.
\end{align*}$$

If we could convert each node to look like the single location examined above, the approximation of $\text{VEUE}$, would repeat the operating reserve demand curve at each node.
ELECTRICITY MARKET

Operating Reserve

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.
ELECTRICITY MARKET

Operating Reserve

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

- Transmission Deliverability.
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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.”


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.

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.

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.


“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.”


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.”

ELECTRICITY MARKET

Operating Reserve Requirements

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.”

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.)