The Economics of Capacity Payment Mechanisms in Restructured Electricity Markets

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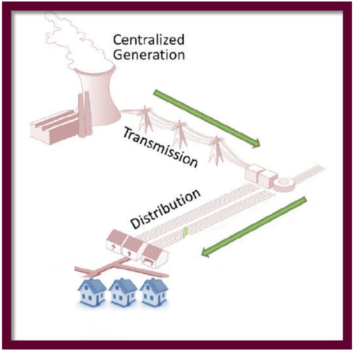
Overview

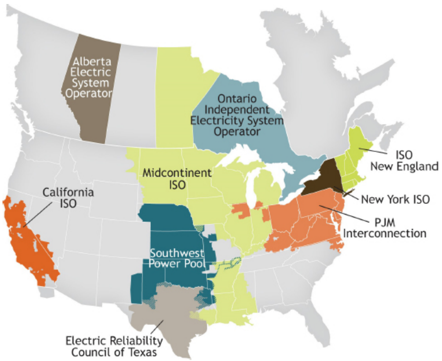
Electricity Markets - Background

- Traditionally - Vertically Integrated Market
- Concerns over performance
  - Rate-of-return regulation
  - Investment risk on consumers
  - Limited incentives to lower cost
  - Economies-of-scale in generation?
- Electricity markets restructured (1980s-Present)
- Transmission & Distribution remain highly regulated
- Generation deregulated ⇒ relies on competitive markets



Electricity Markets - Background

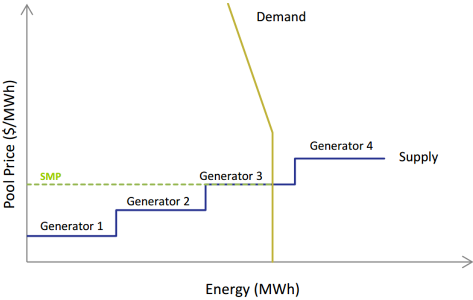
- Restructured markets exist worldwide
  - US, Canada, England, Australia, Nord Pool, Chile, Brazil, Italy, Japan (2020), etc.
- These complex markets are coordinated by an *Independent System Operator*
- Substantial diversity in market design
- Redesigned wholesale power markets
  - Principal component - wholesale procurement auctions



Electricity Markets - Wholesale Procurement Auctions

- Uniform-priced multi-unit auctions
- Hourly (or sub-hourly) procurement auction
- Market-clearing price - intersection of the offer curve and demand
- Ideally, the wholesale price is the primary price signal to drive investment and production decisions
- Electricity markets have numerous complications:
  - (i) limited storage + generation capacity constraints
  - (ii) supply=demand must always hold
  - (iii) market concentration
  - (iv) highly inelastic demand

Figure 2.1: A simplified representation of the energy market



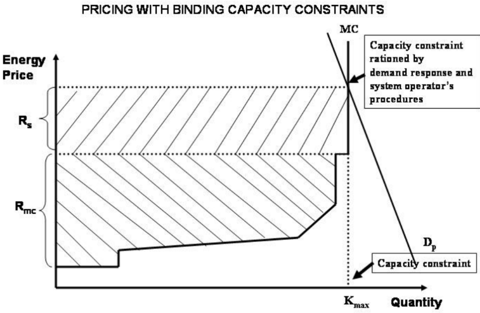
Source: MSA (2012)

Energy-Only Market Designs

- Generators must recover all of their fixed cost of capacity investment in energy markets
  - No explicit payment for capacity value
- Energy-only markets exist in numerous jurisdictions
  - Australia, Nord Pool, Alberta* (prior to 2019), Texas (ERCOT)
- Rely on wholesale prices to send right short-run production signals
- Rely on scarcity pricing to signal for more investment - prices should rise to reflect the opportunity cost of a network failure (VOLL)
- Real-world complications:
  - Concentrated markets → regulations to limit market power (Alberta - OBEGs)
  - Trade-off with static and dynamic efficiency (Brown and Olmstead, 2017)
  - Price-spikes and scarcity pricing are mitigated by price-caps (e.g., $999.99)
  - Demand is highly inelastic → high prices may not reduce scarcity → outages

Energy-Only Markets, Scarcity Pricing, and Missing Money

- Scarcity pricing aims to signal the need for more capacity investment
- Price-spikes and scarcity pricing can have sizable impacts on average prices (e.g., ERCOT)
- Price-spikes can be critical to cover fixed costs of certain technologies (Brown and Olmstead, 2017)
- Regulators limit price-spikes by imposing price-caps in wholesale markets + bid mitigation
- Limits scarcity revenues → mitigates investment incentives
    - Problem is particularly acute for Natural Gas assets



Missing Money, Renewable Support Mechanisms, and Capacity Markets

- Fundamental reliability problem: Highly price-inelastic demand → limited scope for demand reductions, market power concerns, implementing regulations + price-caps
- Other factors can reduce investment incentives in non-renewable capacity (i.e., gas)
    - (i) Out-of-market renewable subsidy mechanisms → suppress future wholesale prices - Growing concerns in the EU and US
    - (ii) Policy uncertainty
- Sizable uncertainty over the future energy market revenues for non-renewable generation in an energy-only market - could be attenuated by allowing more credible scarcity pricing
- Motivated numerous jurisdictions (including Alberta) to adopt capacity payment mechanisms to "keep the lights on" - aims to correct for the market failure in investment
- Capacity markets compensate resources for the capacity (generation potential) they provide to the network

Alberta's Transition to a Capacity Market

Existing framework:

- Energy-only restructured electricity market
- Limited market power mitigation (OBEGs) - motivate investment
- Fossil-fuel heavy portfolio (Gas + Coal 90% of generation in 2015 (AUC, 2017))
- Excess generation capacity and reserve margins, low NG prices

Substantial changes in market design and trajectory:

1. Adjusted carbon pricing mechanism - SGER to CCR (Brown, Eckert, Eckert, 2017)
2. Coal unit phase-out by 2030
3. Competitive renewable electricity procurement program
4. 30% of generation from renewables

Alberta is choosing to transition to an energy + capacity market design

Capacity Market Fundamentals

Transition to a market design with capacity + energy market mechanisms

1. Capacity market fundamentals:
   - Compatible with a competitive wholesale market
   - Promotes system reliability via more revenue certainty
   - Can promote both dynamic and static efficiency
2. **Not all capacity market designs are created equal - details matter!**
   - Learn from experience in other jurisdictions
   - Defining details upfront is critical - regulatory certainty (tough with time constraints)
3. Need to carefully design the *market-based energy system*
   - Price-signals are critical, simply compensating resources for capacity with existing energy markets may not be enough
   - Can lead to misallocation of revenues → inefficient generation portfolio mix (concerning with growing intermittent renewables)
   - Inefficient allocation of capacity costs to load-serving entities can distort incentives for load-shifting and promotion of demand response

Capacity Market Fundamentals

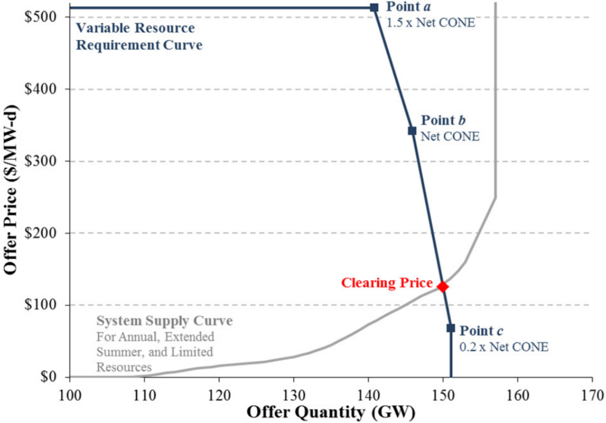
- Capacity payment mechanisms are being adopted and considered worldwide
  - Adopted: US - (PJM, ISONE, NYISO), Alberta, Brazil, United Kingdom, Chile, Spain, Peru, among others
- Capacity market designs and methodology vary greatly by region
- Focus: *"Energy Markets with Forward Reserve Requirements and Centralized Capacity Markets"* (e.g., PJM, ISONE, NYISO)

Typical Elements and Timing:

1. Annual capacity market occurs t years in advance of energy markets (e.g., 1 - 5 years)
2. System operator specifies a demand curve for capacity (reserve requirement on LSEs)
3. Generators* submit bids into capacity market (existing and new resources)
4. Uniform capacity price occurs where the bid function intersects demand
5. Load-serving entities are allocated capacity costs based on "coincidental peaks"
6. Resources earn capacity payments (1 - 3 years) - capacity performance obligation
7. Daily and hourly energy markets take place and clear (short-run signals)

Uniform-Price Capacity Auctions

EX: PJM's Reliability Pricing Model - Annual capacity market that occurs 3-years in advance of delivery-year



Source: Pfeifenberger et al. (2011)

Capacity Market Fundamentals

Standard Design Elements and Principals:

- Ideally: capacity resources bids' reflect cost of making capacity available, *net of expected revenues from subsequent energy markets*
- Generators* can still participate in energy markets if they are not called upon in capacity markets
- Load-Serving Entities (e.g, EPCOR) are required to secure capacity obligations to meet peak demand
  - Can secure capacity obligations bilaterally (outside of the capacity auction)
  - The capacity procurement auction serves as a *residual* capacity market - settles uncommitted capacity resources and load obligations
- The system operator formulates an capacity demand curve that aims to ensure there is sufficient capacity to meet future demand

Capacity auctions are complex! Success depends critically on the details.

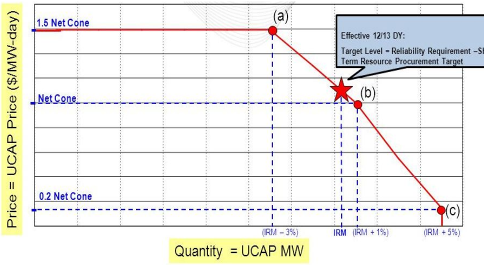
Capacity Requirement and Capacity Demand Curve

System operator sets a capacity reliability requirement - based on peak demand forecast and reliability criteria (LOLE)

Often downward sloping and based on numerous administrative parameters

Critical Pivot Points (e.g., PJM, NYISO):

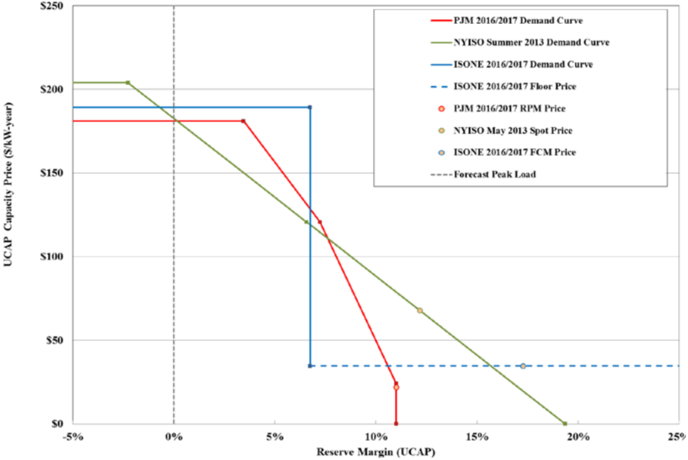
- Cost of New Entry of a representative efficient natural gas combustion turbine unit
- Net of historic energy market revenues (average of three previous years)
- Pivot points are subject to regulator's discretion - impacts slope



Source: PJM (2013)

Capacity Requirement and Capacity Demand Curve

Numerous potential capacity demand curve formulations

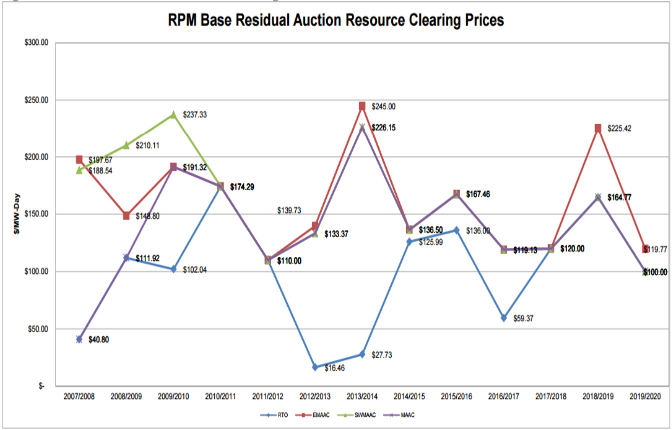


Source: FERC (2013)

Capacity Requirement and Capacity Demand Curve

Capacity payments $\neq$ stable capacity revenues

Figure 2 – Base Residual Auction Resource Clearing Prices



Source: PJM (2016)

Capacity Requirement and Capacity Demand Curve

Criticisms:

- Administrative parameters are controversial and capacity market outcomes very sensitive to parameters (see plethora of Brattle reports 2009 - Present)
- Historical energy market revenues are a poor predictor of future energy revenues
  - Important impacts on the capacity demand curve (Pfeifenberger et al. (2011))
  - Establish a forward-looking energy + ancillary revenues estimate to formulate capacity demand curve (Monitoring Analytics, 2016)
- Tendency to over procure capacity - need to carefully consider how we treat interties and renewable capacity values (Newbery, 2016)
- Excess procurement can create negative dynamic effects (distorts key signals)
  - Suppresses subsequent energy market revenues (creating more "missing money")
  - Increase reliance on capacity market revenues $\rightarrow$ administrative capacity market parameters
  - Expensive - loss of political support can lead to regulatory policy uncertainty - very bad for investment

Resource Participation

Who can participate?

- Traditional fossil-fuel generators (existing and new)
- Demand Response - changes in electricity consumption by end-users from their normal pattern of consumption
  - Can yield substantial peak capacity value - called upon to reduce demand during periods of market scarcity
  - Substantial potential here in Alberta (industrial loads)
  - Forecast on baseline consumption (Chao, 2011; Brown and Sappington, 2016)
  - Capacity and energy market compensation depend critically on estimated baseline
  - Concerns over performance in wholesale markets
  - Should DR receive capacity payments? (very controversial: suppress capacity prices)
  - PJM Lessons Learned: Establish strong performance incentives, requirements, + penalties for resources participating in capacity markets
    - 2014 "Polar Vortex" - DR (and other) resources receiving capacity payments not available

Resource Participation

Who can participate?

- Large penetration of cogeneration - unique to Alberta
  - Determining the capacity value (*net of behind-the-meter load*)
  - Should be compensated for providing capacity above this level
  - Performance payments for provision beyond this level
- Strong performance incentives + penalties are critical to ensure the capacity is available when needed (lesson learned in the US - PJM's Capacity Performance Order FERC 2015)
  - Controversial new definition of capacity resources in PJM - strong requirements on DR and Renewable resources
  - Going forward - need a better way to aggregate resources to qualify as an annual capacity resource (Bothwell and Hobbs, 2016)
  - PJM may be willing to act as an aggregator

Renewable Generation and Procurement - Alberta

Renewable resources will receive payments via the Renewable Energy Program procurement auction - 5,000 MWs by 2030

Should they be able to also receive capacity payments?

- Great Britain does not allow subsidy supported resources to participate
- Some regions include subsidized renewables in capacity markets, but
  - Renewables have limited capacity value and strict performance req. (PJM, 2014)
- Renewables increase competition in the capacity market, but may suppress capacity prices because of out-of-market subsidies
- Growing concerns in regions that resources that receive out-of-market subsides will undermine the integrity of the capacity market (e.g., PJM and MOPR - Ohio, Maryland, Illinois, New Jersey)
- If not included, capacity market demand should be reduced by the expected contribution of renewables to meet peak-load (otherwise, over-procurement (Bothwell and Hobbs, 2016))

Allocating Capacity Market Costs to LSEs

- Load-serving entities (LSEs) are required to secure sufficient capacity to meet their "capacity" obligation (equal to peak-load times a reserve margin)
- Some jurisdictions use a "coincidental peaks" <u>forecast</u> methodology to allocate costs to LSEs (e.g., 5 CPs)
  - May not reflect the true relationship between a LSE's consumers and their need for generation capacity
  - Alternative methodologies rely on previous year's <u>observed</u> coincidental peaks
  - Careful thought needs to go into assessing a LSEs consumers' contribution to the capacity requirement of the electric system
  - Creates important signals for LSEs to shift-peaks and implement Demand Response
  - PJM experience: difficult to change cost allocation mechanisms – critical to get it right upfront (Monitoring Analytics, 2016)

Market Power Mitigation

Alberta's electricity market is likely to remain relatively concentrated

- Market power will be a concern in the energy and capacity markets
- Defense for allowing some degree of unilateral market power no longer exists
- To mitigate market power, regulator should:
    1. Enforce capacity market must-offer provisions for existing facilities (capacity and energy markets)
    2. Create a <u>stable</u> policy framework to encourage investment and participation in energy and capacity auctions (competition!)
    3. Consider imposing bid-mitigation in both auctions on pivotal bidders in periods of high demand
        - Remove OBEGs?
        - Three-Pivotal Supplier Test?
        - Establish a methodology to compute facility-specific cost estimates (not technology-specific)
    4. Set strong performance incentives and penalties to ensure capacity is available during "stress periods"

Price Signals and the Energy System with Increasing Renewables and Capacity Payments

- **Incorrect argument**: Capacity market + bid mitigation → back to a regulated market → no more market-based price signals
- Reliability is more than just simply investment in MWs - not all capacity is identical
- Critical to ensure we are not just throwing $ at MWs
  - Misallocation of $ can lead to an inefficient portfolio of assets + costly
  - Creates structural market problems poorly suited to meet the needs of the system
  - Flexibility is increasingly important with growing renewables
- Capacity market operates in conjunction with energy & ancillary services markets
  - Designing a robust energy and ancillary market to operate in conjunction is essential
  - Market outcomes are critically interrelated
  - Capacity markets impact investment ⇒ impact E&AS supply curves
  - Expected earnings in E&AS markets impacts capacity market bidding behavior

Price Signals and the Energy System with Increasing Renewables and Capacity Payments

1. Wholesale (spot) electricity market
   - Compensation for real-time value of electricity production (or demand-reduction)
   - Spot market settlements at sub-hourly (e.g., 5 minute) intervals - closely links prices with current value
   - Longer existing settlements dampen the time-varying value of generation - important with growing intermittent renewables (Alberta: 60 minute average)
   - *Security constrained economic dispatch* - system operator calls upon units given their spot market bids, ramping up and down capabilities, transmission constraints, and forecast of renewables (important for real-time reliability with renewables)
   - Carbon pricing - implicitly impacts firms' bids via their cost functions - aims to internalize the environmental externality of emissions (Brown, Eckert, Eckert, 2017)

Price Signals and the Energy System with Increasing Renewables and Capacity Payments

2. Locational wholesale spot market pricing
   - Most jurisdictions have adopted some for of location-based pricing
   - Accounts for location dependent grid congestion and losses
   - More important with growing renewables (far from load centers + heterogenous geographical value of renewables (Antweiler, 2015))
3. Robust Ancillary Services Markets
   - Specialty markets used to ensure supply = demand continuously
   - Growing importance with increasing renewables (intermittency + forecast error) - many jurisdictions increasing the ancillary service products (CAISO, ERCOT)
   - EX: Voltage and Frequency control, emergency reserve, operating reserve
   - Rewards fast-start, dispatchable, and flexible assets (e.g., natural gas)
   - Critical price-signal to flexible resources
   - Co-optimized energy + ancillary services markets (SCED) → scarcity pricing penalty factors during short-term periods of tight supply

Price Signals and the Energy System with Increasing Renewables and Capacity Payments

4. Capacity Market (non-renewable technologies)
   - Compensates resources for providing capacity value (MWs) to the power system
   - Serves as a long-run forward hedging market for capacity
   - Not advocating for a technology-specific capacity procurement
   - Capacity market price-signal is net of price signals from energy and ancillary services markets (reward for other technology-specific asset capabilities)
   - Elevates the importance of avoiding over procuring capacity in the capacity market - cause distortion of important price-signals in other markets
5. Renewable Energy Program
   - Aims to subsidize renewable generation technologies
   - Price-signal for renewable capacity resources into the market
   - Contracts-for-differences design implies clearing price is indexed to spot price

Summarizing Price Signals

- Complex web of interactions and price-signals
- What is the “right” and most efficient combination of markets to drive the optimal portfolio of generation units - very complicated
- This is the trajectory of the Alberta market $\rightarrow$ lets ensure that this complex web is designed to provide efficient price signals for asset value
- Critical to “right” drive investment + ensure efficiency of the power system in Alberta

Price-Signals Summarized

1. Wholesale Market - real-time locational value of electricity (including emissions) + SCED
2. Ancillary Services - real-time grid reliability; supply=demand; asset flexibility; scarcity pricing
3. Capacity Market - long-run reliability value of capacity (in MWs)
4. Renewable Procurement - long-run investment of renewable capacity (in MWs)

Are Capacity Markets the Only Way?

Energy-only markets are viewed as the dominant alternative to capacity markets

- Rely only on energy and ancillary service markets to motivate investment
- May not be enough to motivate future investment
  - "Missing Money" problem (price-caps, inadequate ancillary service compensation, bid mitigation, etc.)
  - Reduced investor confidence because of subsidized renewables and policy uncertainty
  - "Missing Market" Problem - long-run market to hedge investment risks (Newbery, 2016)

Experiences:

1. Success: Texas - Energy-Only market with a lot of Wind (15.4% generation)
   - 2011 - faced capacity shortage concerns + low reserve margins
   - 2014 - Elevated wholesale price-cap to $9,000
   - New forecasted reserve margin in 2020 (-0.8% to 20.5%)
   - Why?
     - (i) Reduced demand growth
     - (ii) Large investment in Wind (and a bit of solar)
     - (iii) Large investment of Natural Gas CC (waiting out coal retirements)

Are Capacity Markets the Only Way?

2. England chose to recently adopt a capacity market - concerns that subsidized renewables undermine the economics of private natural gas investment
3. Australia's National Electricity Market - growing renewables and high capacity reserve margin (unexpected low demand growth)
   - 2016 - 2017 outages (issues with market design + ancillary services and potentially strategic behavior, not adequacy)
   - Growing movement to alleviate market power + redesign the market
4. Nord Pool - High scarcity pricing, successfully attracts sufficient capacity investment
5. Numerous regions in the United States (e.g., PJM, ISONE, NYISO) adopted a capacity market years ago because of concerns over the "missing money problem"
6. MISO and numerous other jurisdictions - operate under cost-of-service (rate-of-return) regulation
7. CAISO - bilateral contracting approach + reserve requirement - opaque and high transaction costs

Are Capacity Markets the Only Way?

- What is the "right" market design (and reserve margin)?
- Depends critically on the region's policy objectives and risk preferences:
  - **Energy-Only Markets**: potentially the most economically efficient outcome if the anticipated reserve margin, outage probabilities (reliability), allowance of periodic high price-spikes due to scarcity and market power are publicly acceptable. Comes at the cost of heightened resource adequacy risks, price-spikes, + trade-off between static and dynamic efficiency.
  - **Capacity Payment Mechanisms**: likely most appropriate market design if primary objective is resource adequacy, hitting reserve margin targets, and avoiding high price events. Comes at the cost of potentially higher overall costs, shifting some investment risks onto consumers, and higher administrative burdens.

Conclusions

- "Missing Money" + subsidized renewables + policy uncertainty $\rightarrow$ creates concerns of future investment and resource adequacy in energy-only markets
- Capacity markets aim to promote investment by providing long-run revenue certainty (dynamic efficiency)
- Compatible with traditional energy-markets that can promote static efficiency
- Critical that regulator's think carefully about the synchronization of the energy system with growing renewables + capacity markets - **price signals remain**
- All capacity is not created equal - establish well-functioning markets to send the right price signals - (*not suggesting technology-specific capacity payments*)
- Capacity markets provide more reliability, but are complex and potentially more expensive than an energy-only market design

Conclusions

Details matter - numerous issues to iron out <u>before</u> implementation

1. Defining capacity requirement and LSEs capacity obligations
2. Capacity value of renewables, DR, EE, interties $\Rightarrow$ minimize over-procurement concerns
3. Who receives capacity payments - carefully define "capacity resource" (DR, EE, cogen, imports, renewables)
4. Performance incentives and penalties (e.g., PJM issues)
5. Allocation of capacity costs to LSEs
6. Treatment of market power in capacity and energy-markets
7. Adjust existing E&AS markets to send efficient price-signals with growing renewables - impacts investment and capacity market outcomes (do not wait)

Alberta-Specific Policy Thoughts

- Tight time-frame (2019!) → careful balance between attempting too much and doing too little
  - Risky to focus only on capacity market, and deal with other market details later
- In addition to considering the standard "best-practices" capacity market approach (e.g., 3-year forward, uniform-price, capacity demand curve, etc.):
  - Careful thought process on how to treat Demand Response (participate in capacity market?) and cogeneration
  - Set strong performance requirements + penalties (avoid PJM issues)
  - Location-specific wholesale pricing (geographical diversity in generation)
  - Security constrained economic dispatch + more granular spot pricing
  - Must-offer requirements + market power mitigation in both capacity and energy markets
  - Forward-looking net offset of E&AS in capacity demand model
  - Careful treatment of transmission interties and renewable capacity value
  - Careful thoughts on how to allocate capacity-related costs to LSEs
- Important to establish the operating principals of the energy system going forward to provide market design certainty

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