ELECTRICITY MARKET DESIGN:
Political Economy and the Clean Energy Transition

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The focus on the electricity sector's role in addressing climate change through improved efficiency, development of renewable energy, and use of low carbon fuels creates expanded demands for and of electricity restructuring.

The transformation envisioned is massive, long term, and affects every aspect of electricity production and use.

- Uncertain conditions require a broad range of activities to integrate new technology and practices.
- Innovation requires promoting technologies and practices not yet identified or imagined. "Silver buckshot rather than silver bullets."
- Smart grids can facilitate smart decisions, but only if the electricity structure provides the right information and incentives.
  - Open access to expand entry and innovation.
  - Smart pricing to support the smart grid technologies and information.
  - Internalizing externalities.
    - Price on carbon emissions.
    - Good market design with efficient prices.
    - Compatible infrastructure expansion rules.

A passing reflection on history reinforces the view that there is great uncertainty about energy technology choices for the future. There are many examples of both bad and good surprises.

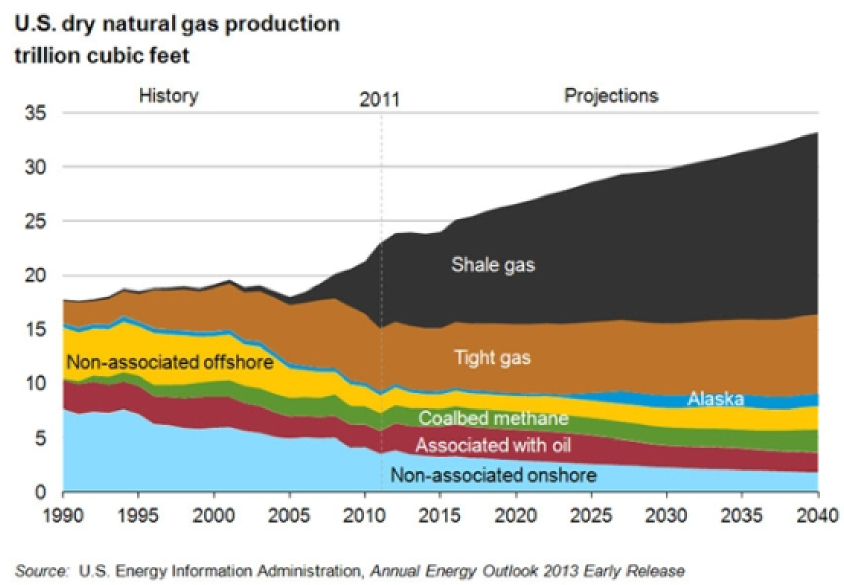
TVA's nuclear plant auction set for November

"The Tennessee Valley Authority, in apparently a first in the US power industry, plans to auction its unfinished Bellefonte nuclear plant in Alabama on November 14 in what amounts to a "fire sale" of epic proportions.

Over more than four decades, an estimated $6 billion was pumped into the project imagined at a time of far different economic and electricity projections and expectations. Bellefonte's minimum asking price — $36.4 million."

(Megawatt Daily, October 18, 2016, p. 3)

U.S. Shale Miracle: Once the technology crossed the market threshold, deployment could be both large and rapid.

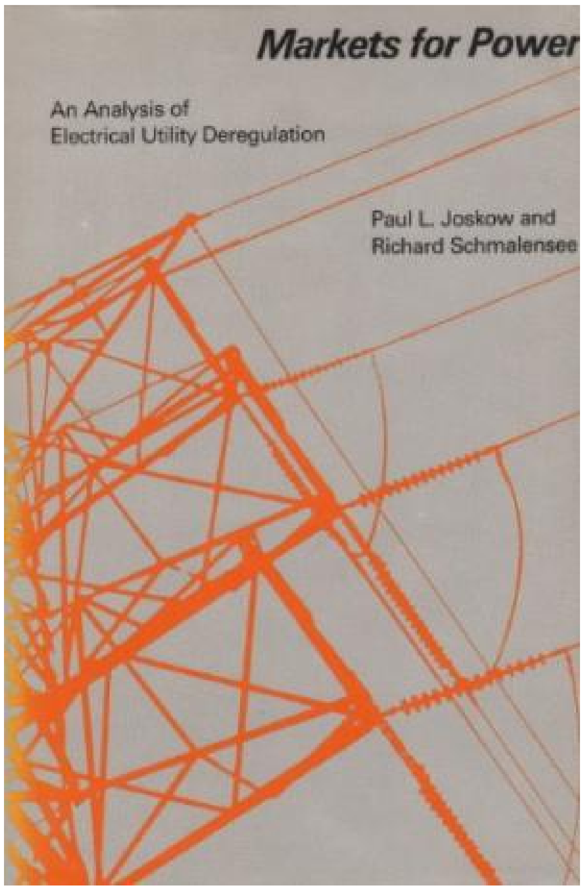


Development of public policy occurs through strong interactions in a political process. Electricity restructuring illustrates many examples of the tensions. Compromise is necessary but not sufficient for policy improvements.

Case	Policy Challenge	Political Complication
Successful Market Design	Open access, Non-discrimination. Physics.	Rent seeking. Conflating trading and markets.
Missing Money	Volatile and high prices were neither volatile enough nor high enough. Resource adequacy concerns.	Rent seeking. Socialized capacity cost preferred over higher prices in some hours.
Demand Response	Fixed price tariffs. Volatile and changing costs of load.	Rent seeking. False equivalence of “negawatts” and megawatts.
Transmission Expansion	Merchant investment would be insufficient. A hybrid market required.	Rent seeking. Hard choices for regulators in implementing the rules.
Green Agenda	Climate and other emission externalities. Inadequate R&D for innovation.	Rent seeking. Divide between deniers and true believers.

Good News

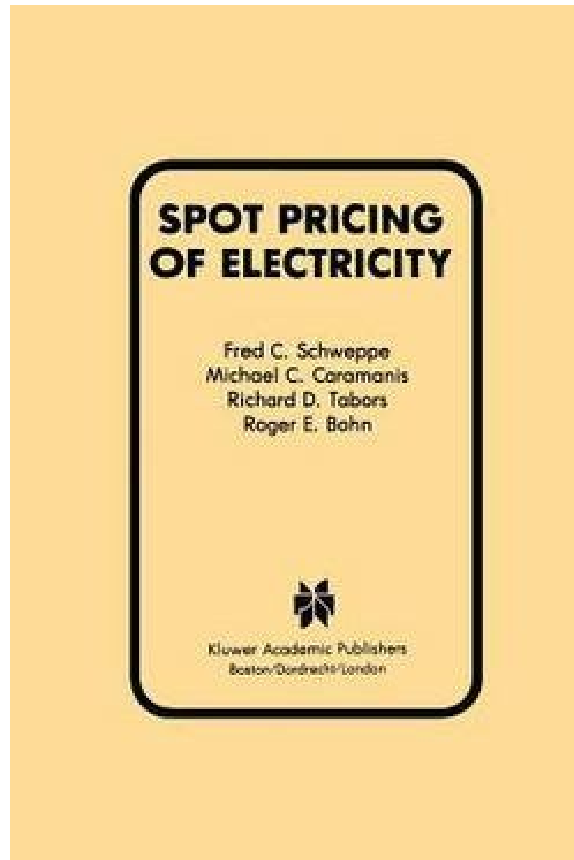
The evolution of electricity restructuring contains a thread of issues related to counterintuitive market design requirements requiring coordination for competition. MIT led the way.



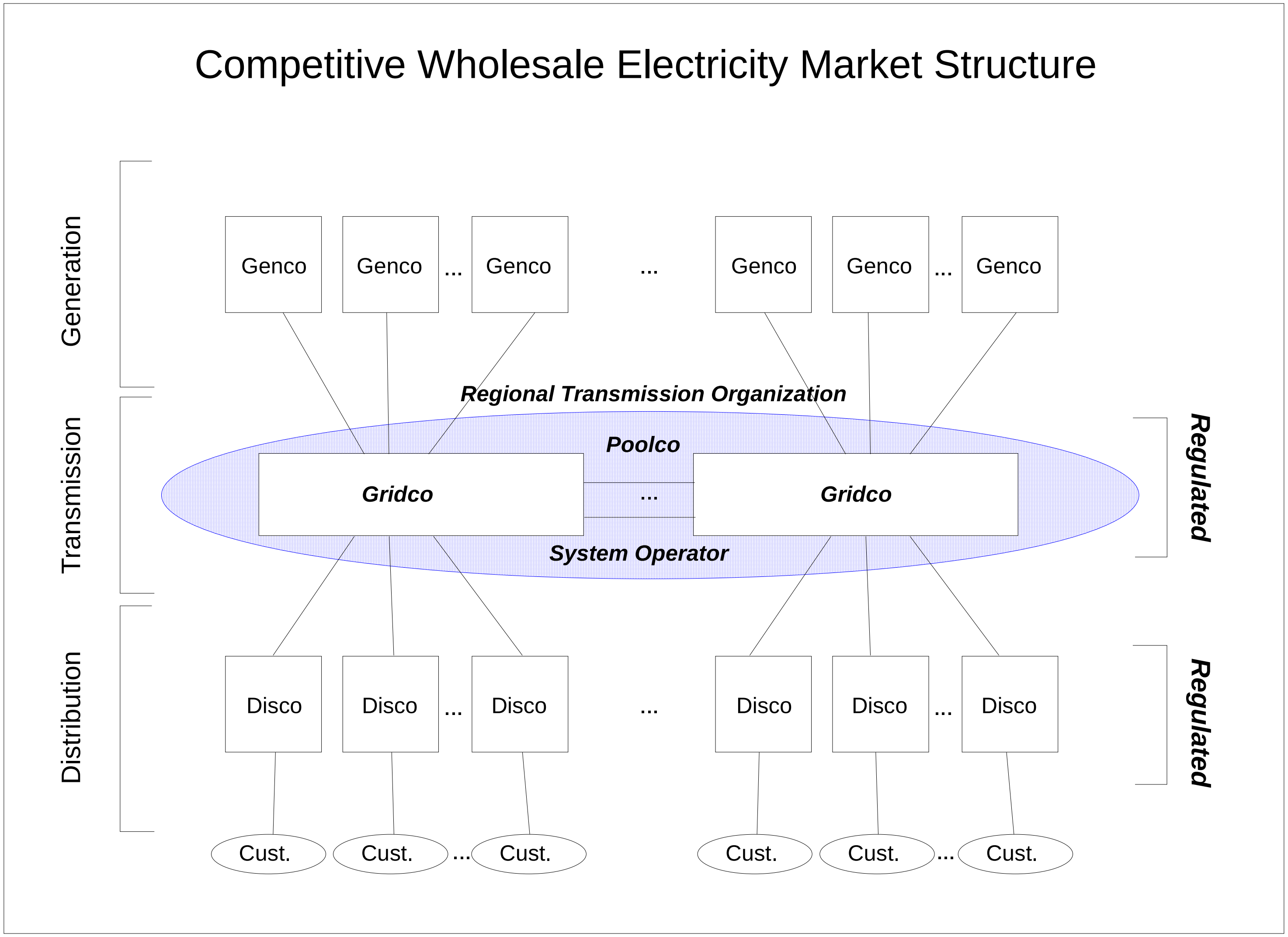
Markets for Power, 1983. Joskow and Schmalensee. Addressed the possibility and problems of introducing competition and markets in the power sector. (Joskow & Schmalensee, 1983)

"*The practice of ignoring the critical functions played by the transmission system in many discussions of deregulation almost certainly leads to incorrect conclusions about the optimal structure of an electric power system.*" (p.63)

Schweppe et al., 1988. <u>Spot Pricing of Electricity</u>, Kluwer. Using prices to direct the dispatch. (Schweppe, Caramanis, Tabors, & Bohn, 1988)



The original arguments for greater reliance on markets emphasized the effects of non-utility generators and the reduction or elimination of the conditions for natural monopoly in generation.



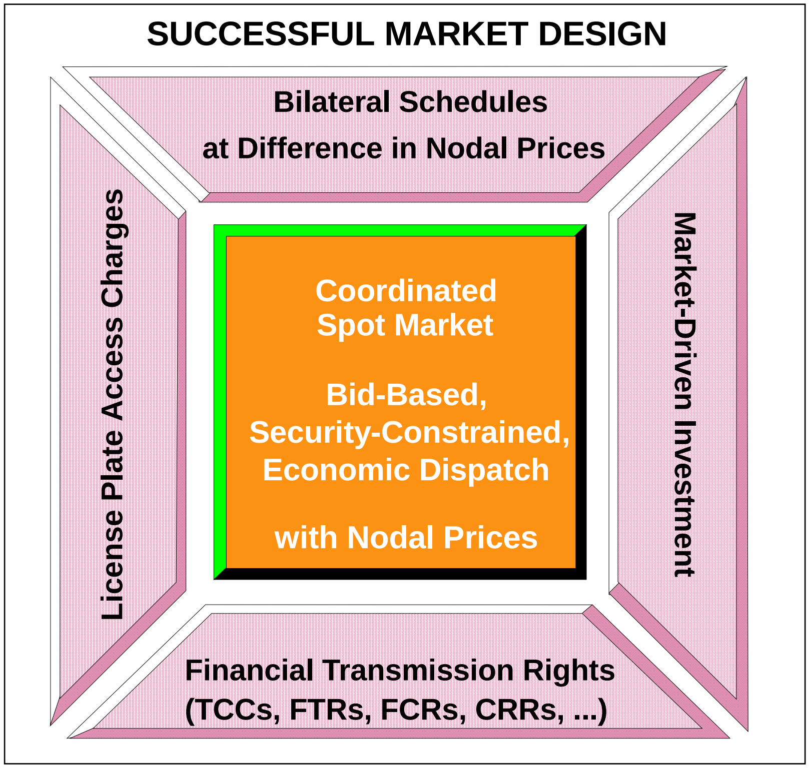
Electricity markets are different. The physics makes it so. The principles of open access and non-discrimination lead to the Successful Market Design (SMD). The pieces fit together to provide the components to support both short- and long-run efficiency.

How did we get to SMD?

- **Why an Independent System Operator (ISO)?**
- **Why economic dispatch?**
- **Why Locational Marginal Prices (LMP)?**
- **Why Financial Transmission Rights (FTRs)?**
- **Why is this important?**

How does this connect to the Green Agenda?

- **Why is innovation important?**
- **Why does electricity market design matter?**
- **Why does the form of policy support matter?**



A common observation is that anything so affected with a public interest must balance competing interests. The recent report by the Staff of the NY Public Service Commission provides an example list of "first principles":

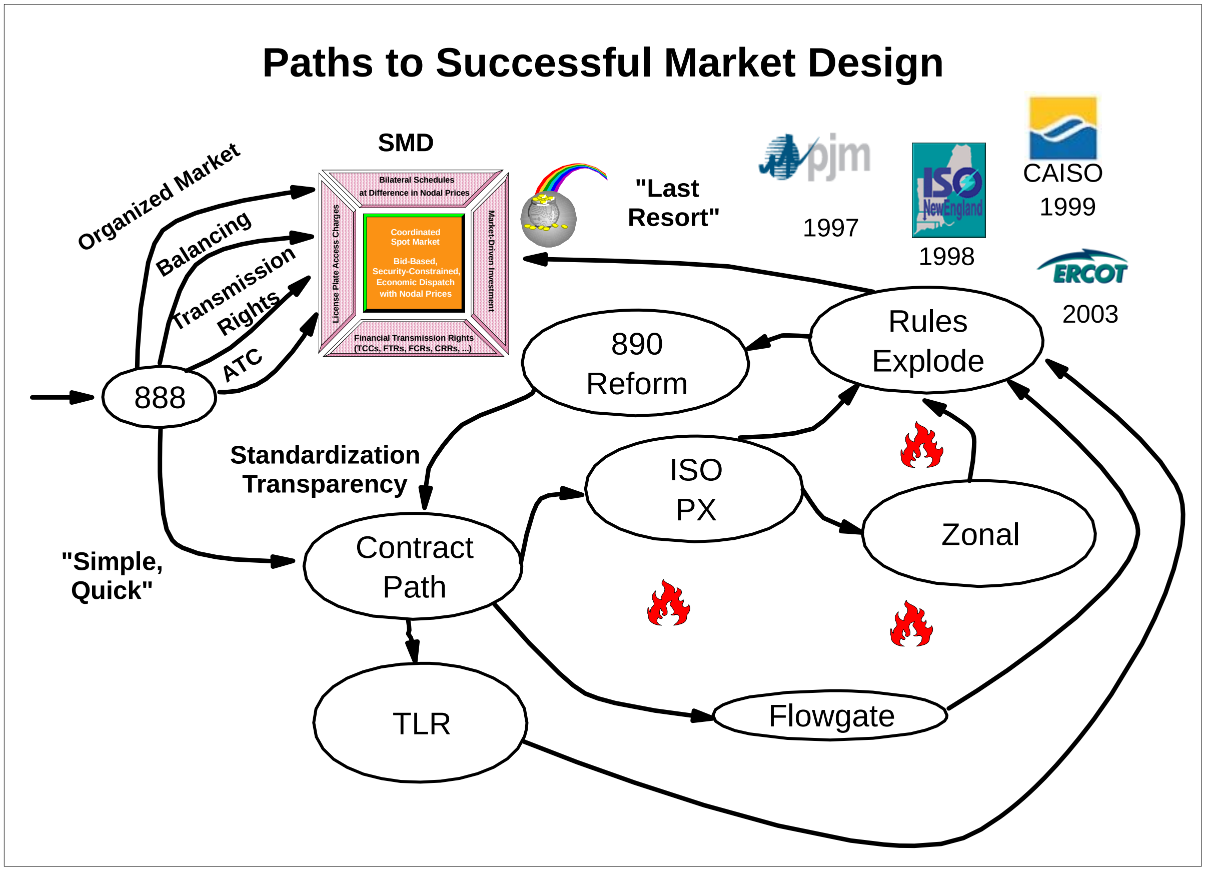
- Increased precision and alignment of valuation of benefits and costs from DERs;
- Clarity and simplicity to ensure customers and developers can use and respond to the methodology;
- Certainty, predictability, and stability to allow market and financing efficiency;
- Gradualism to avoid sudden disruption of DER markets;
- Technology neutrality that accounts for the unique characteristics and performance of different technologies;
- Support for public policy to acknowledge the goals of multiple jurisdictions;
- Breadth to include a greater number of value components than are present under NEM;
- Transparency of valuation methods;
- Flexibility to allow valuation methods to evolve over time;
- Equity and fair access for all customers to the full range of DER technologies; and
- Customer affordability, balancing between support for DER market growth and impacts to ratepayers.

(NYPSC, Staff Report and Recommendations in the Value of Distributed Energy Resources, Proceeding 15-E-0751, October 27, 2016, pp.16-17.)

This list is so broad that it provides little operational guidance. Implementation often invokes another principle:

The Perfect is the Enemy of the Good

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. Early attempts with contract path, flowgate and zonal models led to design failures in PJM (`97), New England (`98), California (`99), and Texas (`03). Regional aggregation creates conflicts with system operations. Successful market design integrates the market with system operations.



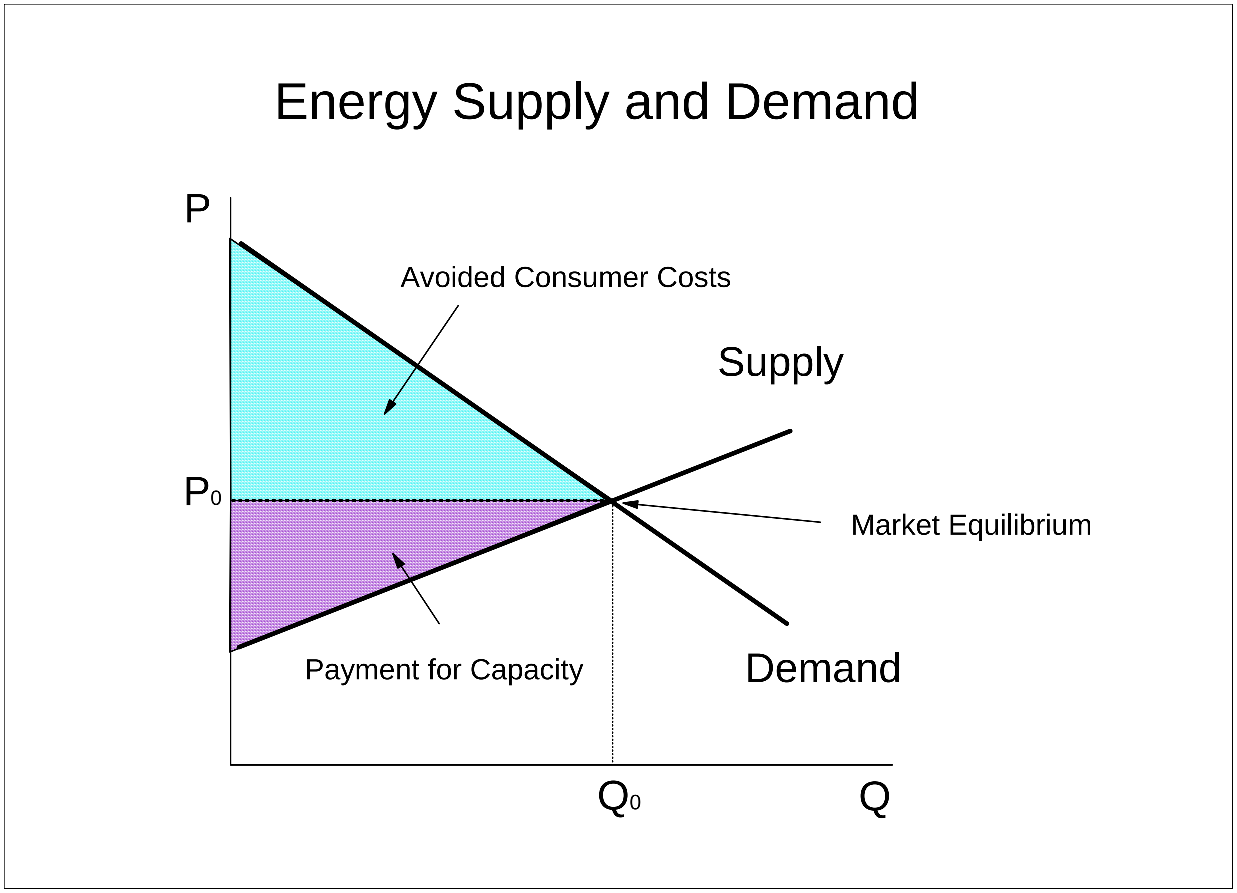
Another perspective for electricity market design is that anything so affected with a public interest must strive to be better than good enough.

The Perfect is the Enemy of the Good?

Or

Good Enough is Neither Good Nor Enough.

The textbook example of a complete market includes total consumer and producer costs. Market-clearing prices support the efficient outcome that maximizes the net social welfare. The structure assumes ease of entry and exit.



Other News

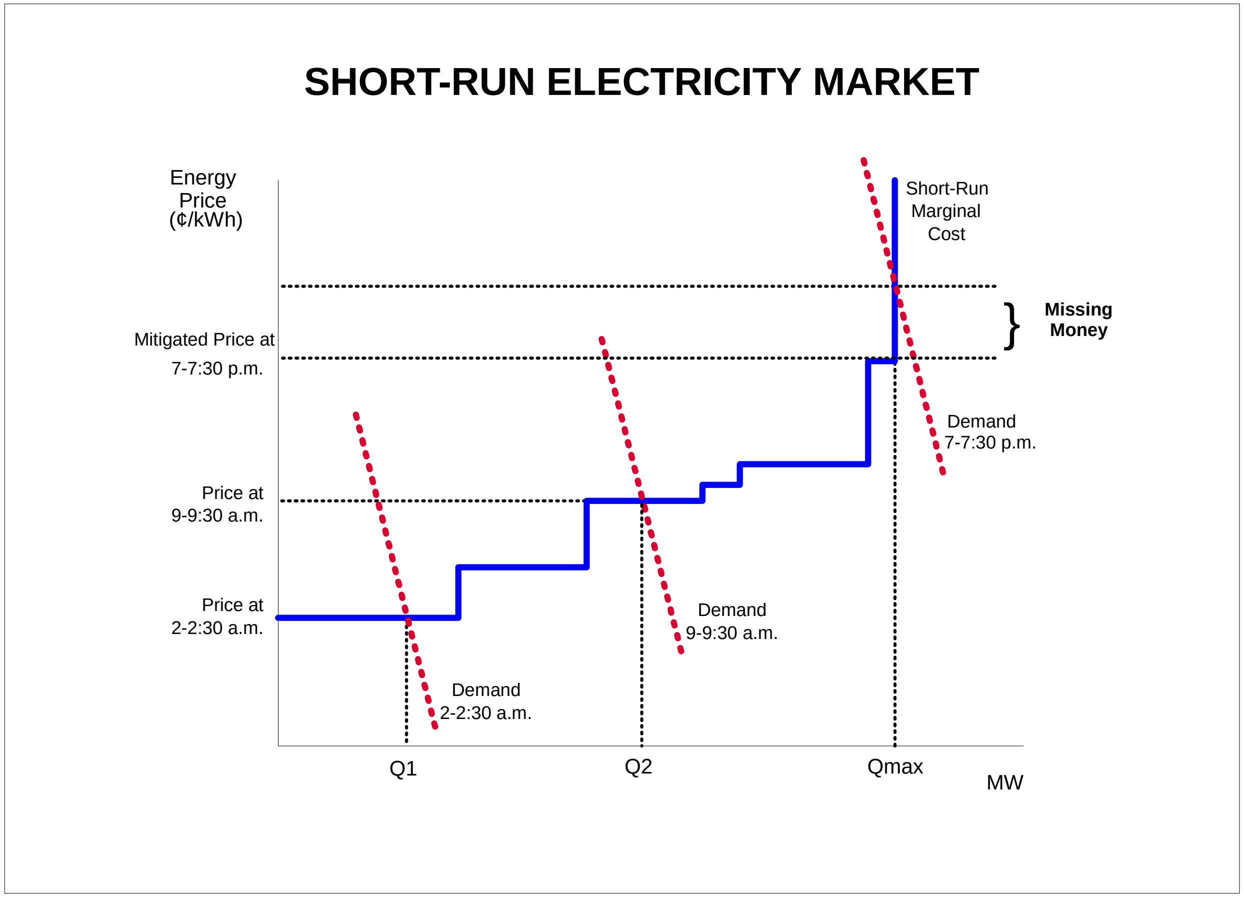
An argument for the deficiencies in electricity markets could be framed as an analysis about incomplete or missing markets.

- **Diagnosis: Incomplete markets can arise for different reasons.**
  - **A Policy Not to Have a Market**
  - **Avoidable Market Design Flaws**
  - **Imperfect Market Implementation**
  - **Market Failures**
    - **Fundamental characteristics of technology**
    - **Correctable market externalities**

- **Prescription: The policy response should reflect the diagnosis.**
  - **Market Reform**
  - **Hybrid Market Design**
  - **Monetization of Externalities**
  - **Targeted Supports for Low Income or Related Policy Purposes**

Missing Money

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. (Joskow, 2008)



Simulations for the ERCOT market illustrate the connection between the missing money and reliability standards.

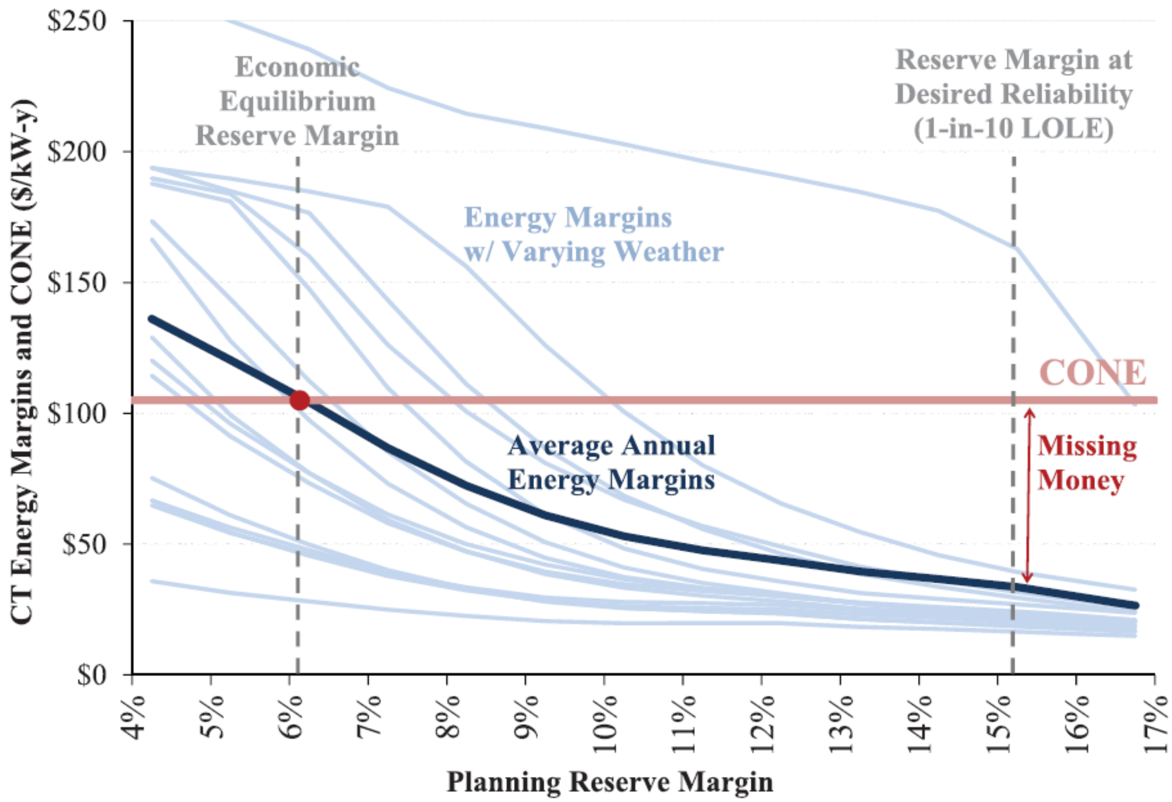


FIGURE 1
Equilibrium Reserve Margin and Missing Money in ERCOT's Energy-Only Market

Spees, K., Newell, S., & Pfeifenberger, J. P. (2013). Capacity Markets - Lessons Learned from the First Decade. *Economics of Energy & Environmental Policy*, 2(2), p. 7. See also (Telson, 1973) (Wilson, 2010)

Different Regions have taken different approaches to achieving resource adequacy.

Administrative and Market-based Constructs for Resource Adequacy

	Administrative Mechanisms (Customers Bear Most Risk)			**Market-based Mechanisms (Suppliers Bear Most Risk)**		
	Regulated Utilities	Administrative Contracting	Capacity Payments	LSE RA Requirement	Capacity Markets	Energy-Only Markets
Examples	SPP, BC Hydro, most of WECC and SERC	Ontario	Spain, South America	California, MISO (both also have regulated IRP)	PJM, NYISO, ISO-NE, Brazil, Italy, Russia	ERCOT, Alberta, Australia's NEM, Scandinavia
Resource Adequacy Requirement?	Yes (Utility IRP)	Yes (Administrative IRP)	Yes (Rules for Payment Size and Eligibility)	Yes (Creates Bilateral Capacity Market)	Yes (Mandatory Capacity Auction)	No (Resource Adequacy not Assured)
How are Capital Costs Recovered?	Rate Recovery	Energy Market plus Administrative Contracts	Energy Market plus Capacity Payments	Bilateral Capacity Payments plus Energy Market	Capacity plus Energy Markets	Energy Market

Notes: For a more detailed discussion of these various approaches to resource adequacy see Pfeifenberger, et al. (2009).
Several markets have a mix of regulated and market constructs within their borders and so are not perfectly represented under any one of these categories. For example, MISO's footprint contains predominantly regulated utilities that conduct integrated resource planning, but a resource adequacy requirement is imposed on all LSEs, which include both regulated utilities and competitive suppliers. MISO will also conduct short-term backstop capacity auctions starting 2013/14.

Spees, K., Newell, S., & Pfeifenberger, J. P. (2013). Capacity Markets - Lessons Learned from the First Decade. *Economics of Energy & Environmental Policy*, 2(2), p. 4.

The ISONE capacity market pay-for-performance reform provides for penalty payments during shortage periods. A shortage period is defined as a 5-minute interval when any of the several operating reserve penalty factors are invoked.

Performance Scoring

The performance score is the difference between the resource's actual performance and a share of its capacity supply obligation (CSO). Actual MW is the dispatch of energy and reserves in the shortage interval. There are no exemptions or exceptions.

$$\textit{Score} = \textit{Actual}\ \mathrm{MW} - \mathrm{CSO\ MW} \times \textit{Balancing Ratio}.$$

$$\textit{Balancing Ratio} = (\textit{Load} + \textit{Reserve Requirement}) / \textit{Total CSO MW}.$$

FCM Performance Payments

$$\textit{FCM Payment} = \textit{Base Payment} + \textit{Performance Payment}$$

$$\textit{Base Payment} = (\mathrm{FCA}\ \textit{Price [-PER]}) \times \mathrm{CSO\ MW}.$$

$$\textit{Performance Payment} = \textit{Performance Payment Rate} \times \textit{Total Score}$$

ISONE, "FCM Performance Incentives October 2012," Strategic Planning Initiative, p. 14-15.

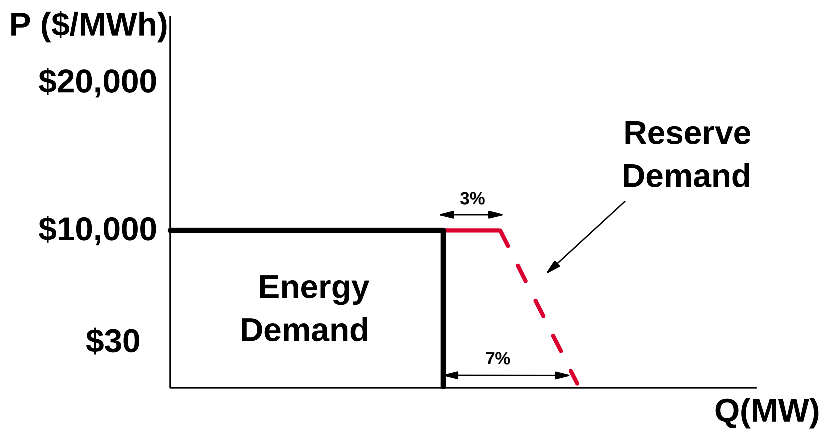
"ISO-NE proposes to phase-in this [Pay for Performance] rate as follows: $2,000/MWh for the period June 1, 2018 through May 31, 2021; $3,500/MWh for the period June 1, 2021 through May 31, 2024; and $5,455/MWh for the open-ended period starting June 1, 2024." FERC Docket ER14-050, January 17, 2014, p. 4.

The ISONE pay for performance approach moves closer to efficient pricing, but not all the way.

- **Reserve Constraint Penalty Factors.** The reserve penalty factors are still low compared to the value of reserves and the value of lost load. “Accordingly, we will direct ISO-NE to submit as part of the compliance due within 45 days of the date of this order Tariff revisions increasing the Reserve Constraint Penalty Factors for 30-Minute Operating Reserves, from $500/MWh to $1,000/MWh, and 10-Minute Non-Spinning Reserves, from $850/MWh to $1,500/MWh.” FERC, “Order on ISONE Tariff Filing,” Docket ER14-1050, May 30, 2014, p. 43.
- **Performance Payment Rate.** “The External Market Monitor supports ISO-NE’s proposal but recommends two modifications affecting the phase-in approach. First, the External Market Monitor … states that the proposed initial Capacity Performance Payment Rate of $2,000/MWh is reasonable because it implies a value of lost load of roughly $30,000/MWh, which is consistent with the External Market Monitor’s estimated value of lost load of $20,000-30,000/MWh. However, it asserts that ISO-NE’s proposed Capacity Performance Payment Rate of $5,455/MWh, which would go into effect for the Capacity Commitment Period 2024-2025, implies a value of lost load of roughly $120,000/MWh based on actual shortages in 2013, a level that the External Market Monitor states exceeds even the highest estimates of the value of lost load. … Second, the External Market Monitor recommends that the Commission consider requiring the introduction of a slope or steps in the Capacity Performance Payment Rate to distinguish between small and deep shortages.” FERC, “Order on ISONE Tariff Filing,” Docket ER14-1050, May 30, 2014, p. 21-22.
- **Performance Payment.** The performance payment is a transfer among capacity suppliers. The performance payment does not affect load prices or provide direct incentives for demand participation.

Operating reserve demand curve would reflect capacity scarcity.

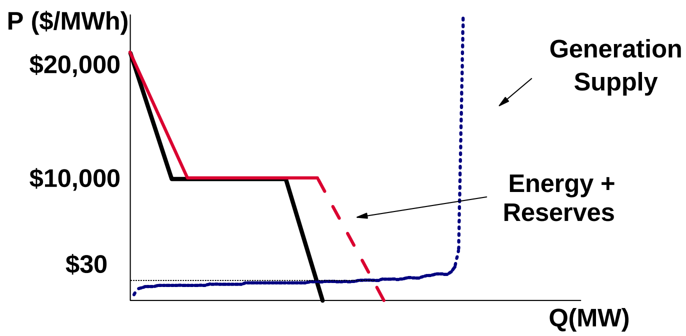
Illustrative Reserve Demand



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 senstive.

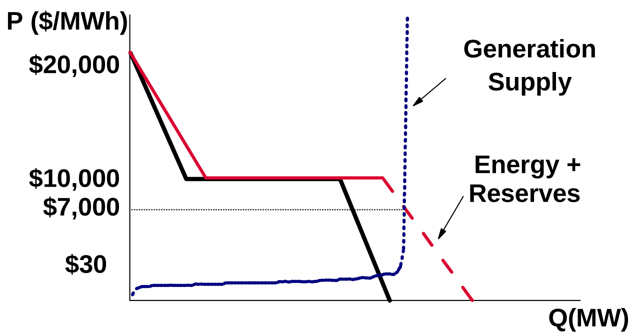
Market clearing addresses the "missing money" that results from inadequate scarcity pricing.

Normal "Energy Only" Market Clearing



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

Scarcity "Energy Only" Market Clearing



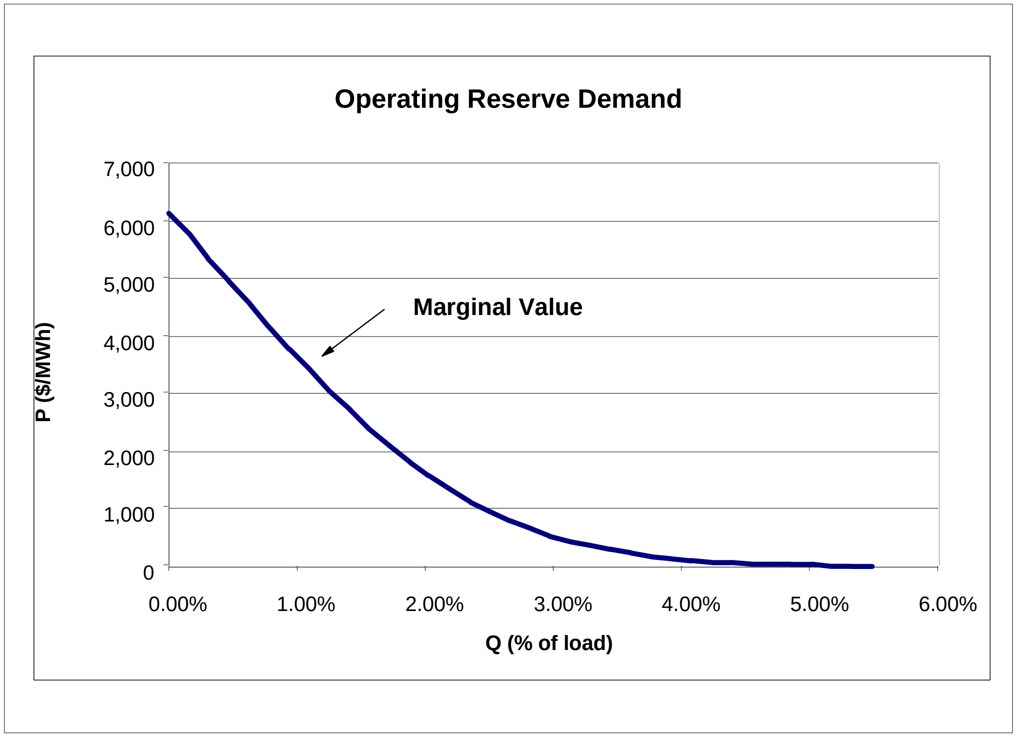
When demand is high and reserve reductions apply, there is a high price.

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.[1]

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.



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

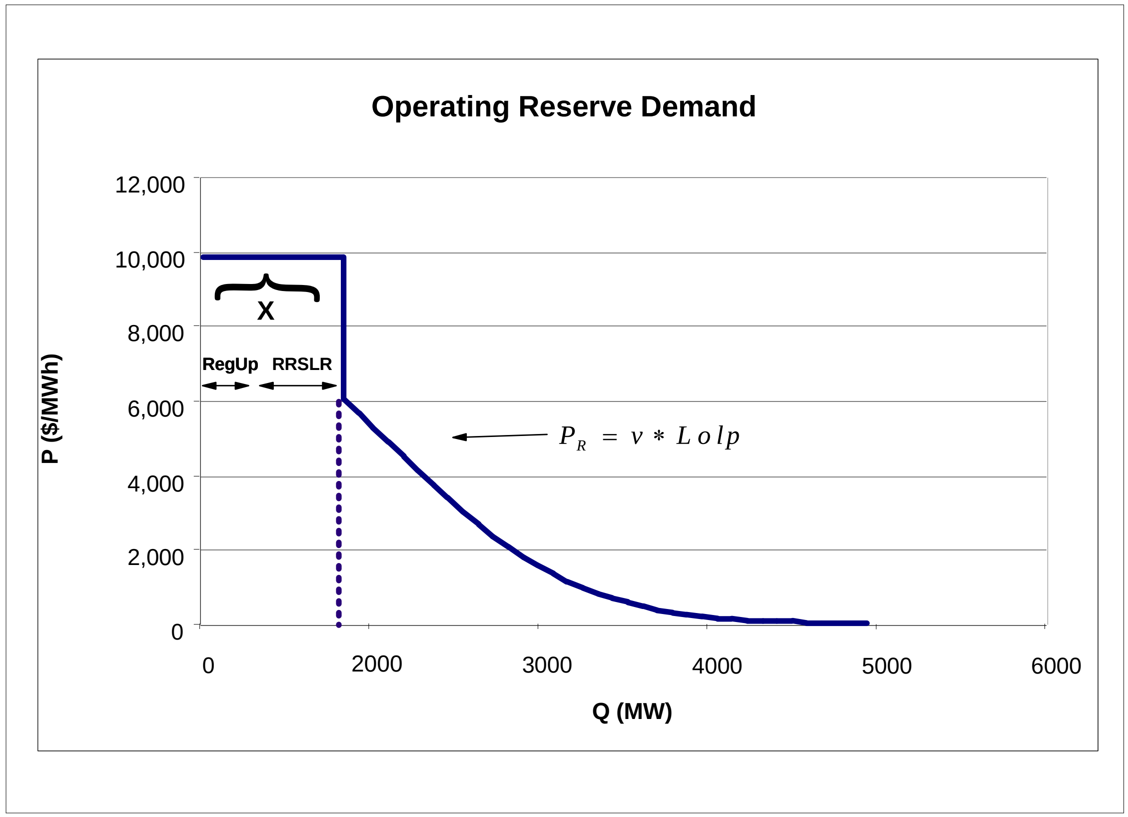
The deterministic approach to security constrained economic dispatch includes lower bounds on the required reserve to ensure that for a set of monitored contingencies (e.g., an n-1 standard) there is sufficient operating reserve to maintain the system for an emergency period.

Suppose that the maximum generation outage contingency quantity is r_{Min}. Then we would have the constraint:

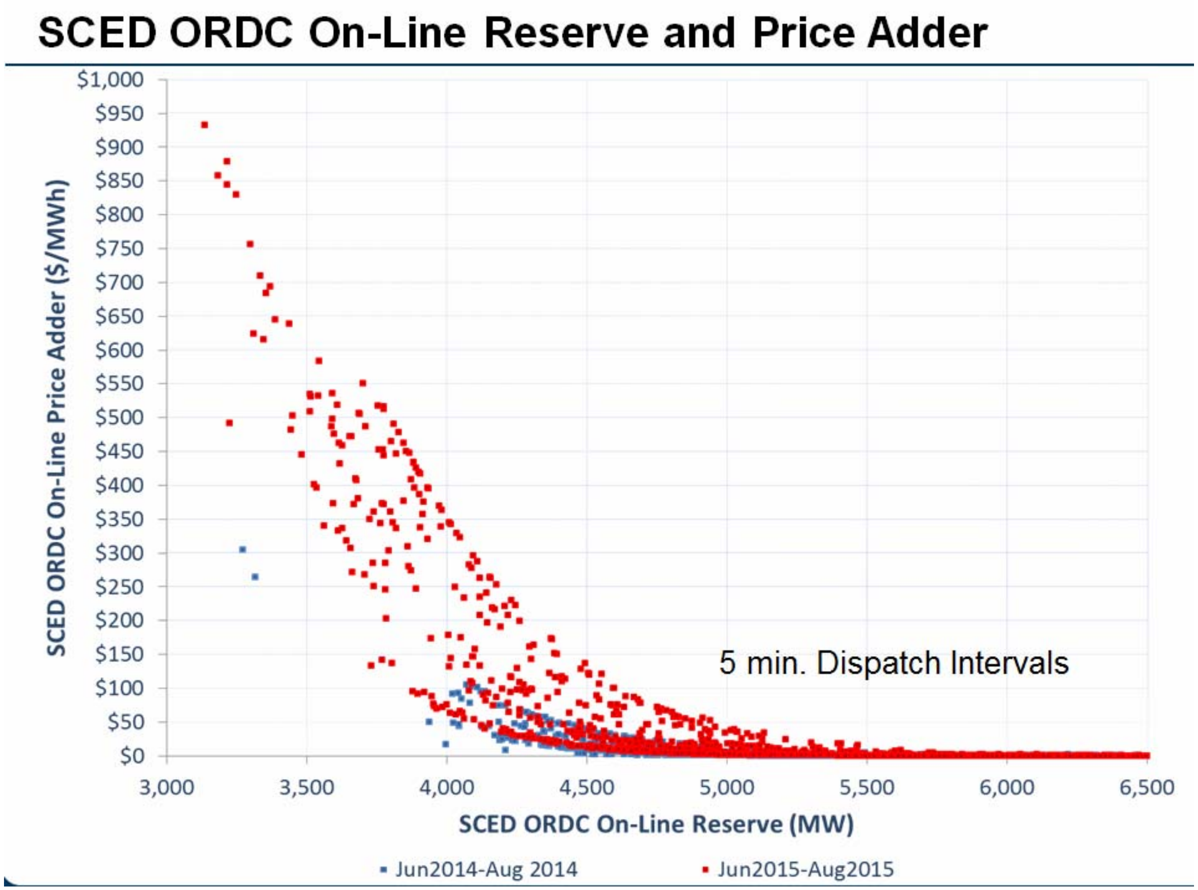
$$r \geq r_{Min}.$$

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 marginal price at r=0 applies. If the outage shocks allow excursions below the security minimum during the period, the reserve price starts at the security minimum.



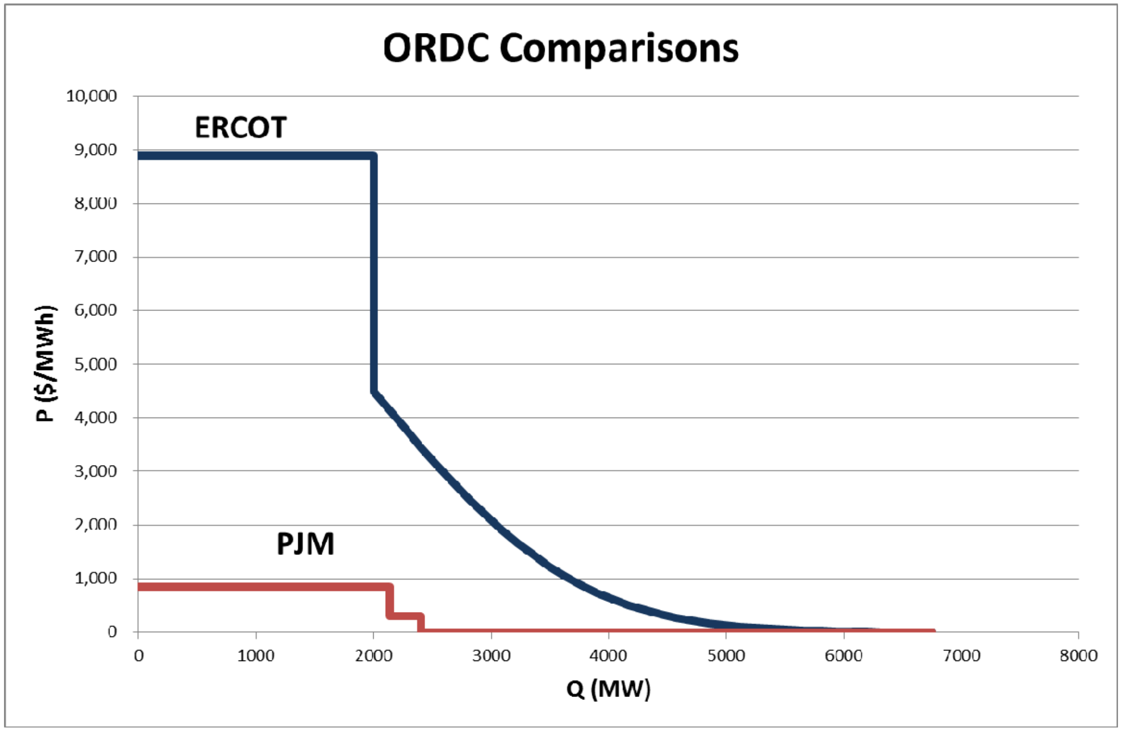
ERCOT launched implementation of the ORDC in in 2014. The summer peak is the most important period. The first year results showed high availability of reserves and low reserve prices. The experience in 2015 illustrates the fundamental properties of the ORDC, and higher reserve prices.



Source: Resmi Surendran, *Analysis of Reserves and Prices, July 2, 2015-August 23: Hour Ending 17:00*, ERCOT TAC Presentation, August 27, 2015.

Other RTOs have long used ORDCs, but without building the design on basic principles.

- **Limited to Declared Shortage Conditions.** "The ORDCs PJM currently utilizes were designed under the assumption that shortage pricing would only occur during emergency operating conditions and therefore the curves are a step function." (PJM and SPP, "Joint Comments Of PJM Interconnection, L.L.C And Southwest Power Pool, Inc. Addressing Shortage Pricing," FERC Docket No. RM15-24-000, November 30, 2015.)
- **Based on the Cost of Supply, not the Value of Demand.** "[T]he $300/MWh price is appropriate for reserves on the second step of the proposed ORDC based on an internal analysis of offer data for resources that are likely to be called on to provide reserves in the Operating Day." (PJM, Proposed Tariff Revisions of PJM Interconnection, L.L.C., Docket No. ER15-643-000, December 17, 2014)



Demand Response

Experience with market design reform suggests examples of bad and good practice.

- **Demand Bidding**
    - **Demand Participation:** Charge demand the market price for load taken. A natural fit with good market design.
    - **Demand Response:** Pay demand for the load not taken. An unnatural fit spawned by flat retail rate design. (Cicchetti & Hogan, 1989)

"At a technical conference on the proposed rulemaking Sept. 13, Wellinghoff recalled Harvard University economist William Hogan "saying that a megawatt [sic] … was not equal to a megawatt." Hogan, supported by the Electric Power Supply Association, has said FERC's proposal would pay certain consumers far more than what is necessary to get them to use electricity more efficiently.

"During the technical conference, Hogan argued that, while a "negawatt" of demand response may have certain features in common with a megawatt of supply, they are both physically or economically different.

"I have great respect for Bill Hogan; I think he's a great professor and a very intellectual man," Wellinghoff said Sept. 14. "I just think he's saying the wrong thing and being paid by the wrong people." …

"It's an epic battle that I've been one of the soldiers in for 30 years … to ensure that the demand side is given equal treatment to the supply side," Wellinghoff said. "I think that equal treatment is absolutely essential."

(Lynn Doan, "Wellinghoff: I am a 'soldier' fighting in an 'epic battle' for demand response," SNL Power Daily, September 15, 2010.)

Demand response pricing "double payment" is a prime example of bad practice. "FERC made a mistake. FERC should fix it." (Hogan, 2016a)

- **Order 745. The demand response policy.**
  - A flawed pricing mechanism. "I decided not to consume electricity. Please send me a check."
    - Selling without Buying. The "negawatt" doubletalk. (Borlick, 2010)
    - Order 745 cost-benefit test for negawatts was prima facie evidence of flawed incentives.
  - "Ultimately, given Order 745's direct regulation of the retail market, we vacate the rule in its entirety as ultra vires agency action. … if FERC thinks its jurisdictional struggles are its only concern with Order 745, it is mistaken. We would still vacate the Rule if we engaged the Petitioners' substantive arguments." (DC Circuit, May 23, 2014) (Reversed by the Supreme Court, Jan. 25, 2016)
  - "In reviewing that decision, we may not substitute our own judgment for that of the Commission. The "scope of review under the 'arbitrary and capricious' standard is narrow." … A court is not to ask whether a regulatory decision is the best one possible or even whether it is better than the alternatives. Rather, the court must uphold a rule if the agency has "examine[d] the relevant [considerations] and articulate[d] a satisfactory explanation for its action[,] including a rational connection between the facts found and the choice made." Ibid. (internal quotation marks omitted). And nowhere is that more true than in a technical area like electricity rate design: '[W]e afford great deference to the Commission in its rate decisions.'"[2] (William W. Hogan, "Demand Response: Getting the Prices Right," Public Utilities Fortnightly, March 2016, pp. 20-23.)

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[2] Supreme Court of the United States, "Federal Energy Regulatory Commission v. Electric Power Supply Association et al., Certiorari to the United States Court Of Appeals for the District of Columbia Circuit," No. 14–840. ENERNOC, Inc., et al., Petitioners, 14–841, v. Electric Power Supply Association, et al. On Writs of Certiorari To The United States Court Of Appeals For The District of Columbia Circuit, January 25, 2016. p. 30.

Transmission Expansion

A transmission infrastructure mandatory cost allocation framework requires a hybrid system that is regional in scope and compatible with the larger market design. FERC Order 1000 proposed principles compatible with a larger hybrid system.[3] **The broader framework would include:**

- **Cost Benefit Framework**
  - Gold Standard: Net Benefits > Total Cost
  - Cost Sharing: Commensurable with Benefits
  - Compatible with Larger Market Design
- **Ex ante Estimation and Allocation**
- **Net Benefits = Change in Expected Social Welfare**
  - Counterfactual without contracts
  - Uncertainty and Expected Present Value
- **Approximations of Benefits**
  - Reliability
  - Economic
  - Public Policy
- **Benefit estimates commensurable across categories for projects**
  - Transmission lines affect all categories of benefits.
  - Transmission costs cannot be separated into distinct buckets.

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[3] Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Docket No. RM10-23-000; Order No. 1000, Washington DC, July 21, 2011. See also (Hogan, 2011).

The current transmission cost allocations are at odds with good market design, court decisions, and plain common sense.

- **Order 1000. Transmission cost allocation.**
  - **In Theory:** "The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. … Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities." (FERC Order 1000, ¶ 622, 637)
  - **In Practice:** "To summarize, the lines at issue in this case are part of a regional grid that includes the western utilities. But the lines at issue are all located in PJM's eastern region, primarily benefit that region, and should not be allowed to shift a grossly disproportionate share of their costs to western utilities on which the eastern projects will confer only future, speculative, and limited benefits. … The petitions for review are granted and the matter once again remanded to the Commission for new proceedings."(7th Circuit, June 25, 2014)

The Order 1000 basis of the PJM transmission cost allocation reflects the contradictions of beneficiary pays without basing the allocation on the benefits.

"PJM's allocation of cost responsibility for RTEP reliability baseline upgrades in accordance with these provisions is beneficiary based. Typically, load growth creates conditions that constitute violations of reliability criteria, which in turn require upgrades for eliminating the violations. The benefit to load from elimination of the violation will differ from the benefit of having the resultant upgrade available for use to deliver PJM generation to serve them. However, the benefit derived by the load in a transmission zone can only be determined by the use of the upgrade to deliver PJM generation to this load zone relative to similar uses of the upgrade by other zonal loads. This quantifiable benefit is then used to determine the relative responsibility for the cost of the system upgrade(s) for each zone. …"

"Regional and Necessary Lower Voltage Facilities with estimated costs greater than or equal to $5 million

- 50% of the cost of the upgrade will be assigned annually on a load-ratio share using the PJM Network Transmission Service Peak Load and the applicable load values for Merchant Transmission having Firm Transmission Withdrawal Rights for the 12-month period ending October 31 preceding the calendar year for which the annual cost responsibility allocation is determined
- 50% of the cost of the upgrade will be assigned annually on a directionally-weighted solution-based DFAX methodology

Lower Voltage Facilities (<345kV) with estimated costs greater than or equal to $5 million

- 100% of the cost of the upgrade will be assigned annually on a directionally-weighted solution-based DFAX methodology"

(PJM Manual 14B: PJM Region Transmission Planning Process, Revision: 30, Effective Date: February 26, 2015, pp. 40-41.)

The PJM Artificial Island Project application of the DFAX methodology raises a challenge to the cost allocation rules under Order 1000.

“The Artificial Island Project is a PJM RTEP project that involves the construction of a new 230 kV transmission line under the Delaware River, and construction and installation of certain other facilities, to address certain system stability and related generation operation issues in the Artificial Island area in southern New Jersey. PJM's Board of Managers ("PJM Board") has adopted the use of the solution-based DFAX methodology to allocate the costs of the Artificial Island Project. … The Commission approved the use of solution-based DFAX for purposes of cost allocation of certain PJM-approved transmission projects as part of a comprehensive cost allocation proposal that the PJM Transmission Owners filed to comply with Order No. 1000. … ***PJM's application of solution-based DFAX to the Artificial Island Project results in the Delmarva Zone, which includes load located within the states of Delaware and Maryland, being assigned approximately 90 percent of the costs of the Artificial Island Project. Other analyses conducted by PJM demonstrate that the Delmarva Zone will receive only 10 percent of the benefits associated with the Project.*** The result is even more egregious given that the generation issues to be resolved by the Artificial Island Project are not located in the Delmarva Zone. Such disproportionate alignment of benefits and costs is unjust, unreasonable, and wholly inconsistent with cost-causation principles and legal precedent requiring the allocation of transmission project costs to be "roughly commensurate" with the benefits of the project.”

(Complaint of the Delaware Public Service Commission and Maryland Public Service Commission, FERC, Docket No. EL15-95-000, August 28, 2015, Emphasis Added).

The PJM Artificial Island Project cost allocation protests raised an important policy issue. In addition, the evolving conditions raised parallel concerns about cost effectiveness.

"Complainants contend that application of the solution-based DFAX method to the Artificial Island Project in the Delmarva zone results in a disproportionate alignment of benefits and costs that is unjust, unreasonable, and inconsistent with cost causation principles. ***We disagree.*** The courts have recognized that no cost allocation method can perfectly assign costs to the beneficiaries of a transmission project, particularly in the case of a transmission grid." (FERC, *Order Denying Complaint and Accepting Cost Allocation Report*, Docket No. EL15-95-000, April 22, 2016, Emphasis Added).

"I acknowledge that these cases present difficult questions regarding ex ante cost allocation methodologies, and I understand the reasoning and considerations that led the Commission to reject the complaints. Determining an appropriate cost allocation methodology for large transmission projects has been among the most complicated issues presented during my time on the Commission.

Nonetheless, I do not agree with the orders' denial of the complaints. Based on the record, particularly as developed through the technical conference, I am persuaded that the complainants have met their burden to establish that the use of solution-based DFAX to allocate the costs of the Bergen-Linden Corridor Project and the Artificial Island Project is unjust and unreasonable." (Commissioner Fleur Dissent, Docket No. EL15-95-000, April 22, 2016).

PJM Board Suspends Artificial Island Transmission Project

Asks PJM to perform review

(Valley Forge, Pa. – August 5, 2016) – The PJM Interconnection Board has suspended the Artificial Island transmission project and directed PJM to perform a comprehensive analysis to support a future course of action. The announcement came today in a letter to PJM members.

Green Agenda

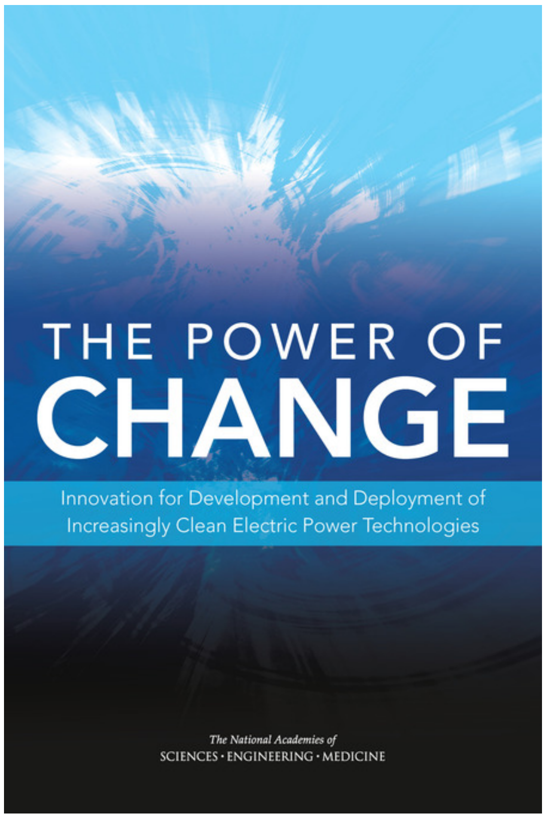
The costs of clean technologies are high, but declining. Success stimulating the development of less expensive will be crucial in achieving the climate goals.

- **RE<C**. The earlier mantra from Google, where renewable energy (RE) is cheaper than coal (C). This would make adoption of renewables an easy choice even without considering the environmental benefits.
- **RE<C+Carbon Price**. The economic welfare outcome that internalizes the carbon externality. Renewable energy is expensive, but it is worth it. Climate policy includes a mix of mitigation and adaptation.
- **RE>C+Carbon Price**. Renewable energy is too expensive, and climate policy leans heavily towards adaptation.

It is important to know where we are and where we are going. The policy prescription depends on the diagnosis.

How and how much should we be supporting the development of clean energy technologies?

A National Academy of Sciences analysis with EIA data provides cost estimates to deal with different subsidies, dispatch requirements and externalities. The levelized cost of energy (LCOE) is an apples-to-apples comparison based on the assumptions and input data for the United States. (National Academy of Sciences, *The Power of Change: Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies*, Washington D.C., 2016, p. 260.)



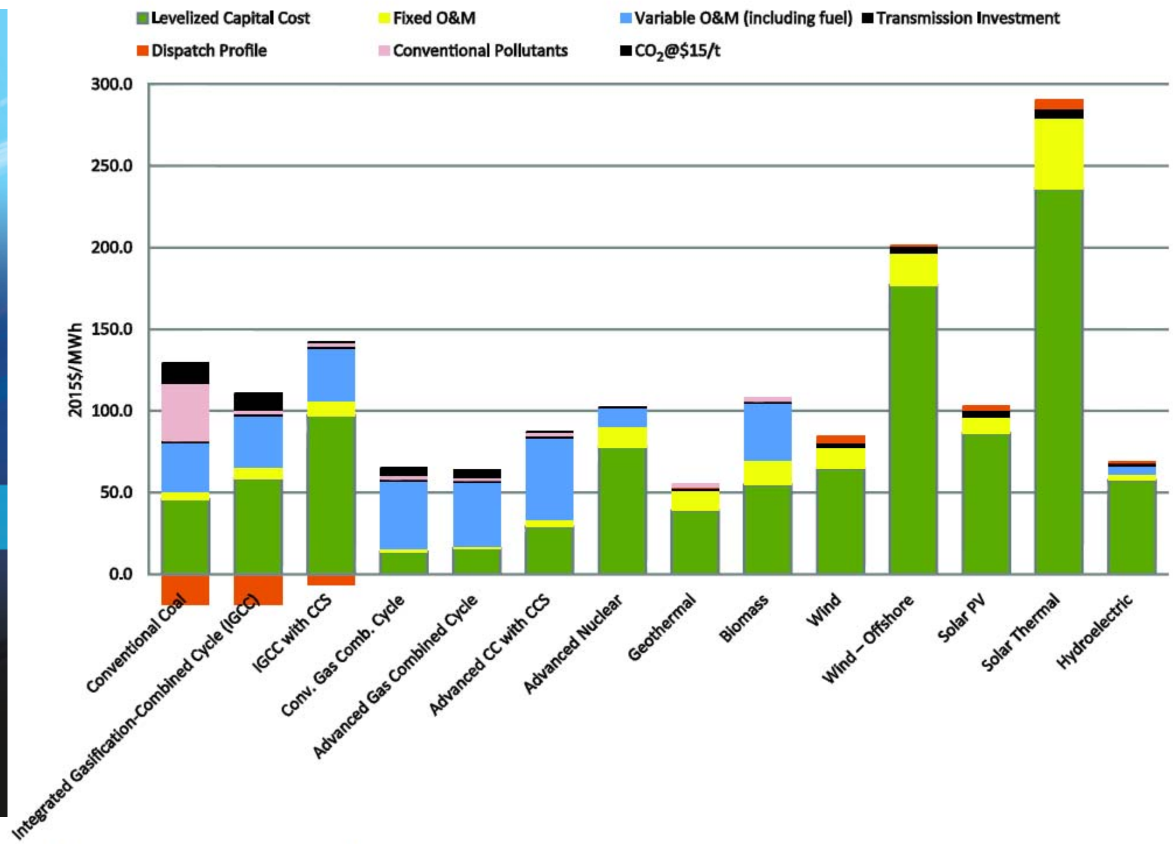


FIGURE B-1 Levelized cost of electricity for plants entering service in 2022 (2015 \$/MWh).

The NAS identified two main barriers and emphasized two "overarching recommendations."
(National Academy of Sciences, *The Power of Change: Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies*, Washington D.C., 2016, pp.3-4.)

Barriers

"The committee concluded that there are two significant barriers to accelerating greater penetration of increasingly clean electricity technologies. First, as noted above, the market prices for electricity do not include "hidden" costs from pollution, stemming mainly from negative impacts on human health, agriculture, and the environment. Levels of criteria pollutants declined over the past three decades, but still cause harms. Harms from GHGs are difficult to estimate, but if accounted for in the market, could be considered by consumers. …

The second barrier is that the scale of the climate change challenge is so large that it necessitates a significant switch to increasingly clean power sources. In most of the United States, however, even with a price on pollution, most increasingly clean technologies would lack cost and performance profiles that would result in the levels of adoption required. In most cases, their levelized costs are higher than those of dirtier technologies, and there are significant challenges and costs entailed in integrating them into the grid at high levels. This means that reducing the harmful effects of emissions due to electricity generation will require a broader range of low-cost, low- and zero-emission energy options than is currently available, as well as significant changes to the technologies and functionality of the electricity grid and the roles of utilities, regulators, and third parties. …

…even if the technological and institutional barriers to greater adoption of increasingly clean power technologies were overcome but their prices were not competitive, an adequate scale of deployment would require tremendous public outlays, and in many parts of the world would be unlikely to occur. While learning by doing can lower some costs, deployment incentives are likely to be insufficient as the primary policy mechanism for achieving timely cost and performance improvements."

The NAS identified two main barriers and emphasized two "overarching recommendations."
(National Academy of Sciences, *The Power of Change: Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies*, Washington D.C., 2016, pp.3-4.)

Recommendations

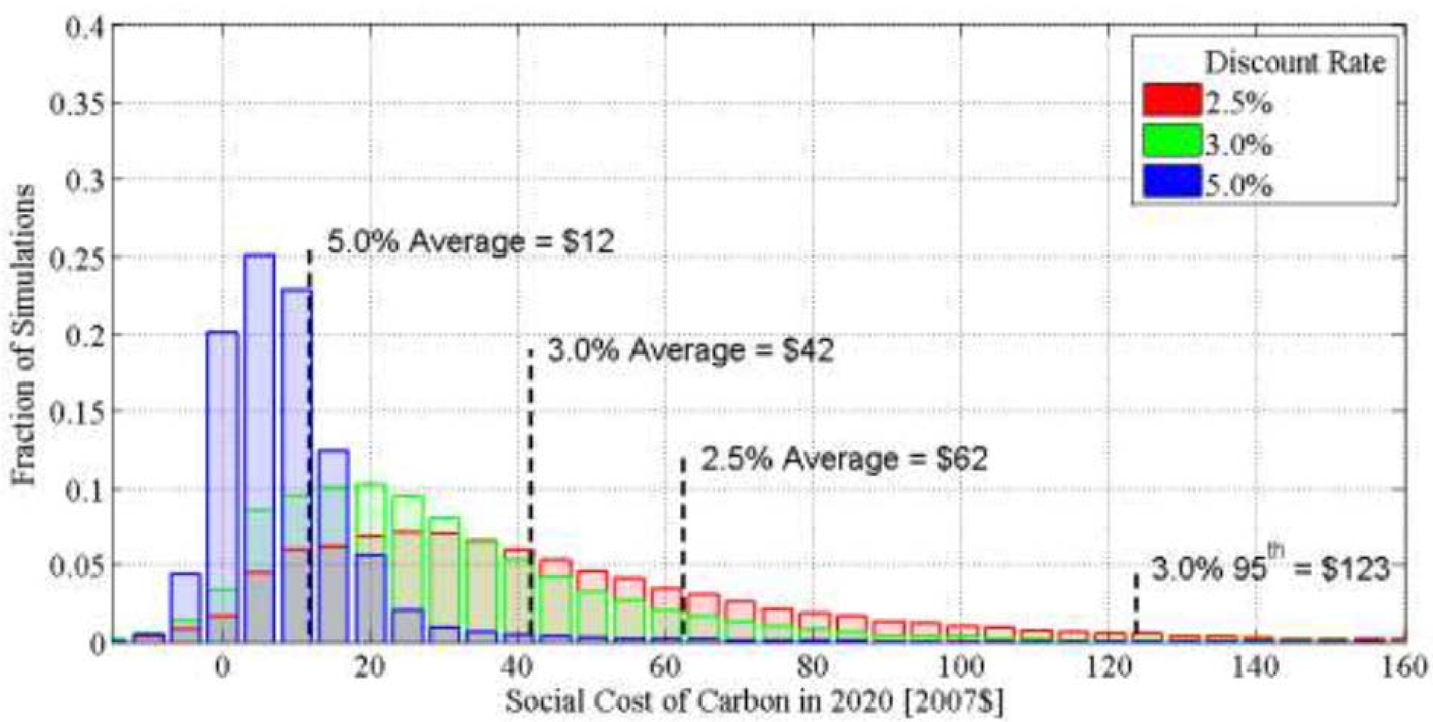
"The U.S. federal government and state governments should significantly increase their emphasis on supporting innovation in increasingly clean electric power generation technologies.

Simply put, the best way to encourage market uptake is first to have technologies with competitive cost and performance profiles. The need for increased innovation and expanded technology options is especially important given the global picture. In many parts of the world, coal remains the cheapest fuel for electricity generation. China, India, and the nations of Southeast Asia are expected to continue rapidly adding new electricity generation facilities, most of them coal-fired and with minimal pollution controls. Thus there is a need for technological innovations that are affordable outside the United States as well. These improvements in performance and cost will be essential to achieve long-term GHG reductions, such as the reduction called for in the COP21 agreement, without significantly increasing electricity prices. …

Congress should consider an appropriate price on pollution from power production to level the playing field; create consistent market pull; and expand research, development, and commercialization of increasingly clean energy resources and technologies.

Correcting market prices will encourage more deployment of increasingly clean technologies. Where such technologies are already the lowest-price choice, they will become even more so; in other locations, a pollution price will make these technologies the most affordable option or narrow the gap. In addition to providing this market pull for the deployment of mature increasingly clean technologies, pollution pricing can be expected to spur the development of new, even more effective and competitively priced technologies."

The challenge of climate change and the impact of carbon dioxide and other greenhouse gas emissions is a textbook example of a market failure. The policy implication is to internalize the cost of carbon. The benchmark for the best policy is a carbon tax. Although there is significant uncertainty, the estimates from the U.S. government imply a substantial social cost of carbon dioxide ($/ton CO2) that is not internalized in the market.



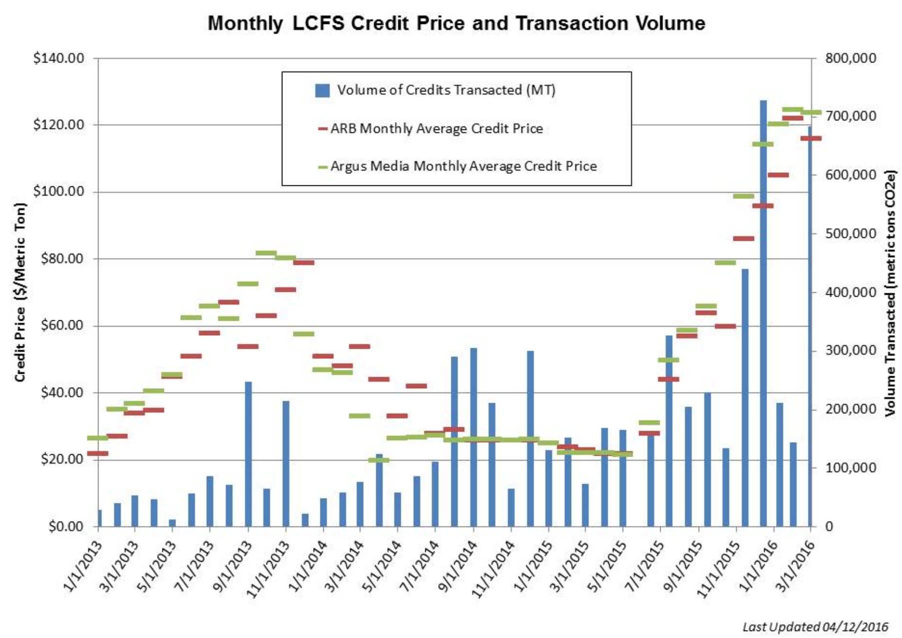
Regulatory Impact Analysis - Under Executive Interagency Working Group on Social Cost of Carbon. (2013). Technical Update of the Social Cost of Carbon for Order 12866, (Revised, July 2015), p. 13.

A carbon tax set at the estimated Social Cost of Carbon does not have to be very accurate to do better than many of the attempts to price carbon indirectly.

In Germany, the implied price of carbon for 2006-2010 ranged from $76 for wind to $740 for solar (Converted for 2007 €/ton CO_2). (Marcantonini & Ellerman, 2015, p. 221)

In California the price of carbon permits has been at the auction floor of $12 compared to the price of $122 for the complementary Low Carbon Fuel Standard (LCFS) (2016 $/ton CO_2). (ICE and CARB data.)

Price of California Carbon Allowance Futures over time from ICE End of Day Reports. Daily trading volume units are 1000 allowance futures. Download source data.



The hidden values that elicit calls for subsidies create their own inefficiencies. Much of the motivation for electricity restructuring sprang from dissatisfaction with "avoided cost" mandates and energy subsidy programs. (Hogan, 2002) **The hidden part of the green agenda is often hidden costs not values.**

> "Subsidies pose a more general problem in this context. They attempt to discourage carbon-intensive activities by making other activities more attractive. One difficulty with subsidies is identifying the eligible low-carbon activities. Why subsidize hybrid cars (which we do) and not biking (which we do not)? Is the answer to subsidize all low carbon activities? Of course, that is impossible because there are just too many low-carbon activities, and it would prove astronomically expensive. Another problem is that subsidies are so uneven in their impact. A recent study by the National Academy of Sciences looked at the impact of several subsidies on GHG emissions. It found a vast difference in their effectiveness in terms of CO_2 removed per dollar of subsidy. None of the subsidies were efficient; some were horribly inefficient; and others such as the ethanol subsidy were perverse and actually increased GHG emissions. The net effect of all the subsidies taken together was effectively zero!
>
> So in the end, it is much more effective to penalize carbon emissions than to subsidize everything else." (Nordhaus, 2013, p. 266)

Opportunities for Doing Better

No design can be perfect, but the record indicates the high costs of ignoring first principles. When "good enough" is good enough, the costs of the unintended consequences can be high. The examples from scarcity pricing, demand response, transmission expansion and the cleaner energy are illustrative but not exhaustive. Many other areas present similar challenges.

- **Out-of-Market Transactions and Price Formation.** (Hogan, 2014)
- **Renewable Portfolio Standards.** (Schmalensee, 2012)
- **Net Energy Metering.** (Brown & Bunyan, 2014)
- **Market Manipulation.** (Lo Prete & Hogan, 2014)
- **Reforming the Energy Vision.** (NYS Department of Public Service, 2014) (Caramanis, Ntakou, Hogan, Chakrabortty, & Schoene, 2016)
- **Hidden Values and the Value Stack.** (NYS Department of Public Service, 2016)
- **Virtual Bidding and Financial Trading.** (Hogan, 2016b)
- **Clean Power Plan.** (Hogan, 2015)
- **Other?**

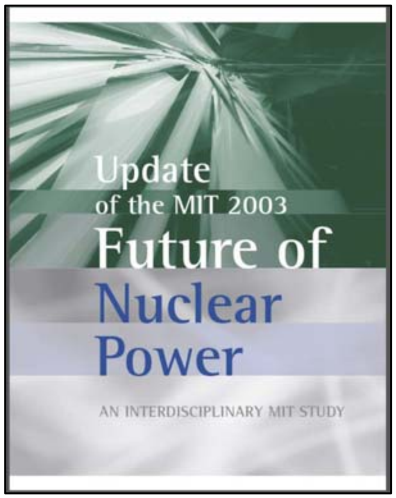
Better News

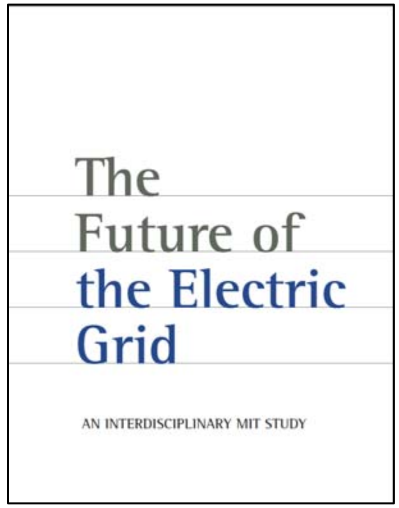
Recent FERC Orders provide examples of slow net progress in improving electricity market design by sticking to fundamental principles and connecting the policy prescription to the underlying diagnosis of market ills.

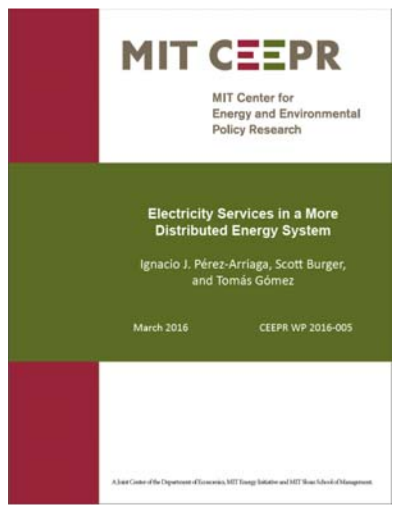
FERC Order 825: "The Federal Energy Regulatory Commission is revising its regulations to address certain practices that fail to compensate resources at prices that reflect the value of the service resources provide to the system, thereby distorting price signals, and in certain instances, creating a disincentive for resources to respond to dispatch signals. We require that each regional transmission organization and independent system operator align settlement and dispatch intervals by: (1) settling energy transactions in its real-time markets at the same time interval it dispatches energy; (2) settling operating reserves transactions in its real-time markets at the same time interval it prices operating reserves; and (3) settling intertie transactions in the same time interval it schedules intertie transactions." (FERC, "Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators," Docket No. RM15-24-000; Order No. 825, June 16, 2016.)

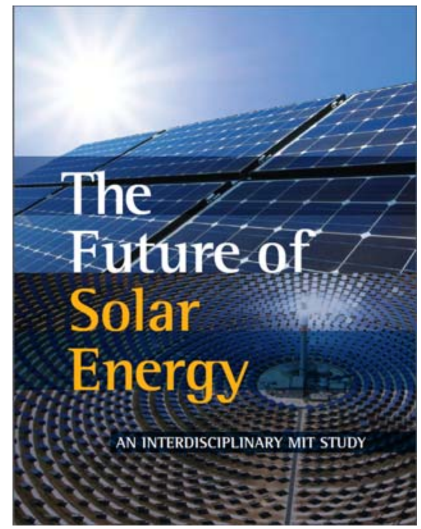
PJM FTR Order. Addressing and correcting many issues related to financial transmission rights, including FTR allocation, underfunding, uplift cost allocation. (FERC, PJM Interconnection, "Order Addressing Filing and Issues Raised At Technical Conference," L.L.C. Docket Nos. EL16-6-001 ER16-121-000, September 15, 2016.)

Work at MIT continues on the forefront of understanding of where we are and where we might be going. Good analysis that transcends political correctness.









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