Electricity Policy and Market Design

Dec 2018 | Michael Hammersley | Protocol Labs

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Regulatory overview, organizations, and responsibilities

Macro-structure of the US grid

At the micro-level, the physical U.S. grid is made up of generation, transmission, and distribution facilities. At the macro-level, however, it's composed of three separate grids: the Western Interconnection, the Eastern Interconnection, and ERCOT (the Electricity Reliability Council of Texas); note that the interconnections include portions of both Canada and Mexico (see figure 1). Though each grid operates to the same standards, they aren't actually synchronized to each other, and the only links are high-voltage DC lines (which, being direct-current, don't require synchronization).

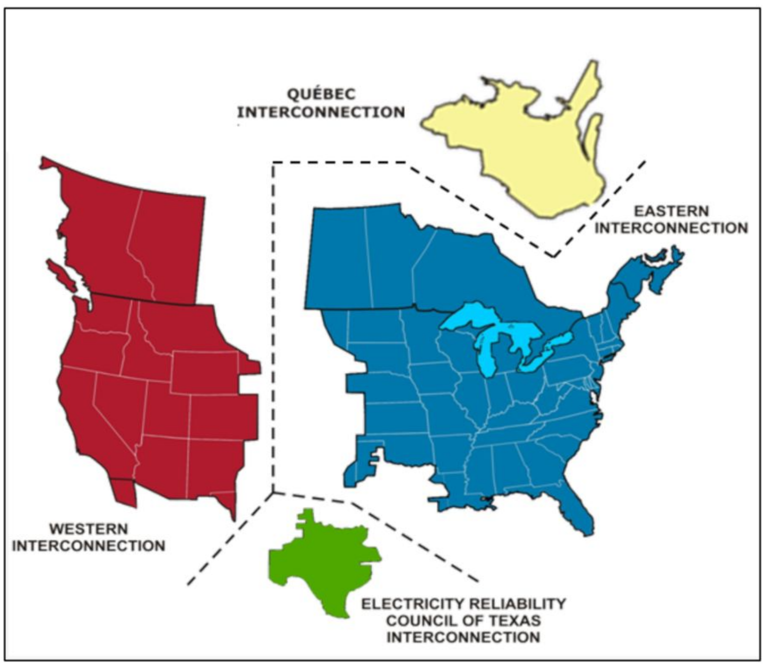


Figure 1. The four major interconnections of North America (from [1]).

The grid is further split into eight regional entities: ERCOT, and seven others that are overseen by NERC (the North American Electric Reliability Corporation). These regional entities are responsible for enforcing security and reliability standards in the grid (see figure 2).

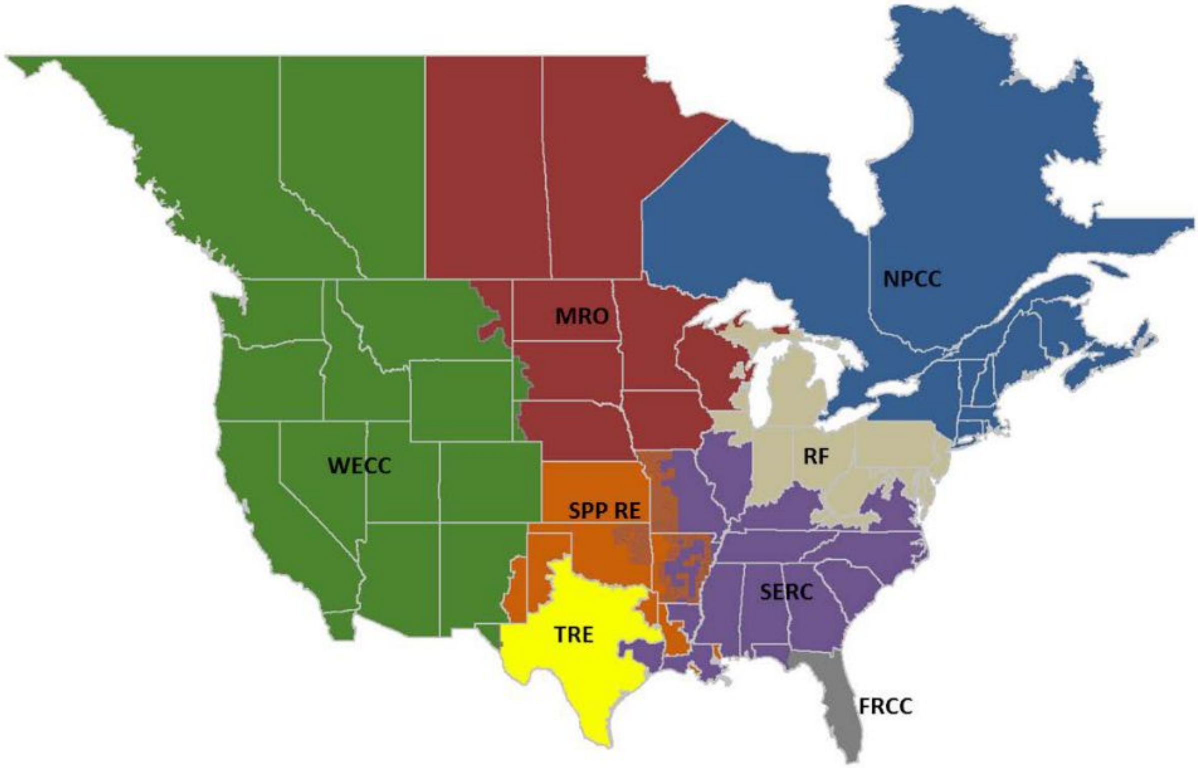


Figure 2. NERC regions for enforcing security and reliability standards (from [2]).

Within these regions, more complicated grids (those involving a lot of power generation around congested transmission corridors) are operated by ISOs (Independent System Operators) and RTOs (Regional Transmission Operators), defined by FERC orders 888 and 2000, respectively. These organizations are independent, not-for-profit balancing authorities that schedule, dispatch, manage transmission, administer wholesale electricity markets, and ensure reliable transmission planning in the region it administers (see figure 3).

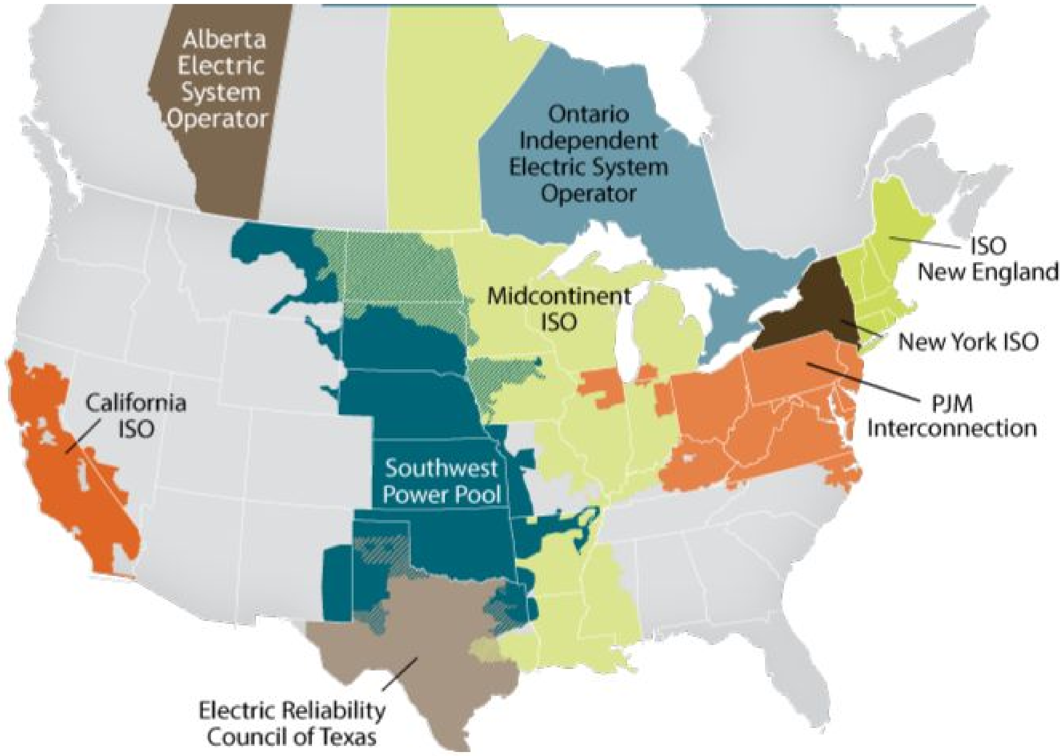


Figure 3. The several Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) that operate the grid in North America (from [2])

Areas not managed by dedicated RTOs/ISOs still have authorities responsible for managing their power flows (see figure 4); these are the local “balancing authorities”. As of 2015, there were about 75 balancing authorities in North America (including a handful in Canada and Mexico) [3]. Note that the RTOs and ISOs are themselves the balancing authorities in the regions they administer.

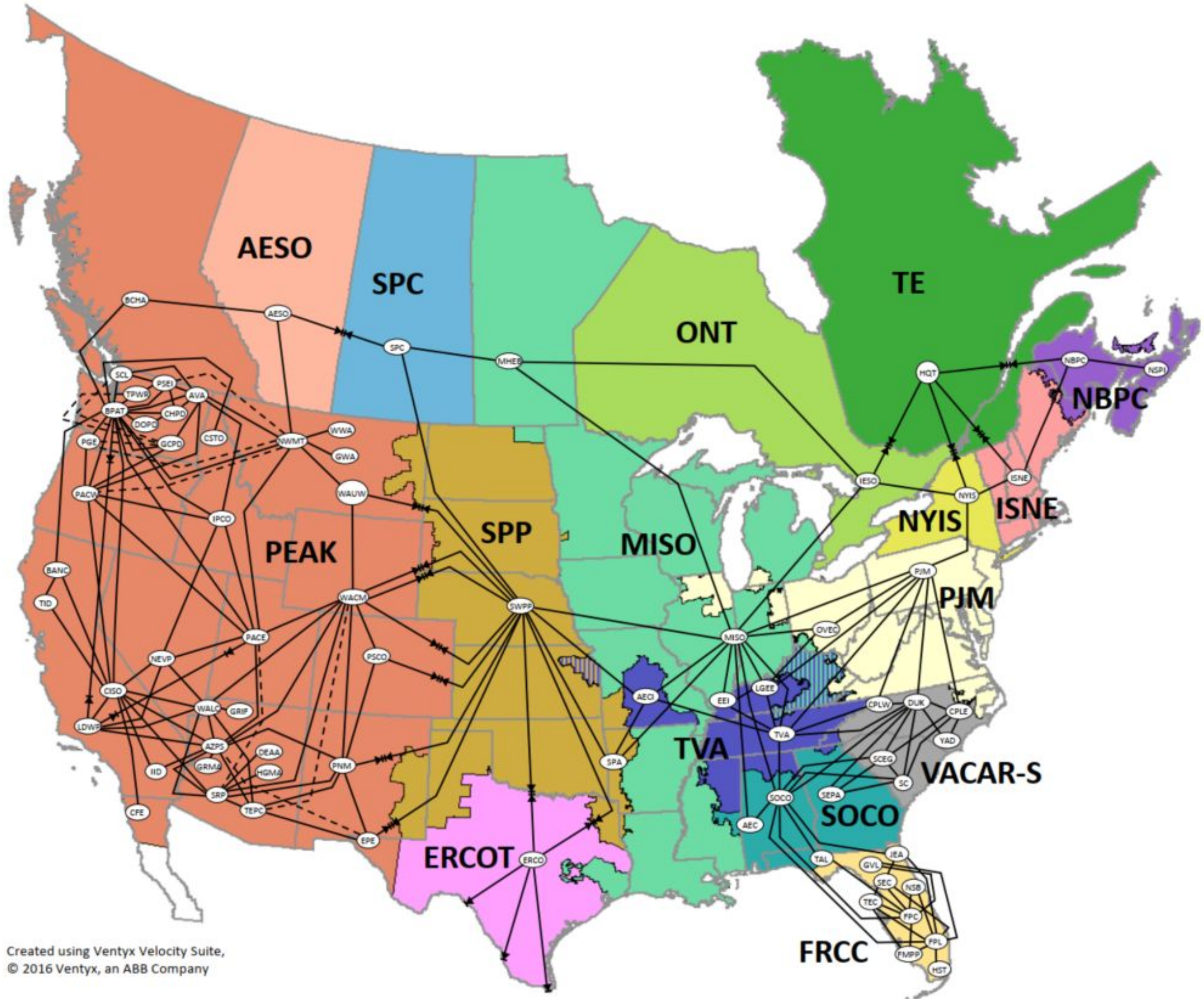


Figure 4. Map of balancing authorities and their overarching reliability coordinators (from [3]) Note that territories overlap somewhat -- though not perfectly -- with the regional entities defined by NERC that enforce security and reliability standards.

Federal Energy Regulatory Commission (FERC)

The Federal Energy Regulatory Commission grew out of the Federal Power Commission, which was given purview to oversee wholesale and interstate electricity transactions in 1935. It includes five commissioners, nominated by the President and confirmed by the Senate, who serve staggered five-year terms. FERC's responsibilities, as they relate to electricity infrastructure in particular, include:

- Overseeing interstate energy transmission;
- Overseeing wholesale energy sales, including investigating and preventing market abuse;
- Setting reliability, certification, and security standards; and
- Setting minimum considerations for state regulatory commissions, including integrated resource planning, distribution, rates, and net metering

FERC has delegated responsibility for setting and enforcing its reliability, interoperability, and security standards to the North American Electric Reliability Corporation (NERC). Over the last three decades, it has also created and maintained the ISO and RTO structures that are increasingly responsible for operating much of the U.S. electrical grid [4]. Both FERC and NERC are taking active steps to successfully navigate the large-scale changes that have already started to sweep through the electricity grid [5].

FERC's purview does not include local distribution, retail, and wholly intrastate facilities (such as exist in Texas, Alaska, Hawaii, Puerto Rico, and the US Virgin Islands). Municipal utilities, rural electric cooperatives, and federal power marketing agencies are also not subject to FERC oversight [6]. (And while FERC's responsibilities also include natural gas pipelines, oil pipelines, and hydroelectric permitting and construction, these regulations are outside of the scope of this report, which focuses on the electricity grid.)

FERC regulates the electricity sector through the use of "Orders", which go through multiple rounds of revision with input from the public and the electricity sector in particular, and which are discussed in more detail below. It also makes party-specific adjudicatory decisions, usually taken in response to submittals from companies, customers, or market participants [4].

State-level regulation

States are given an extraordinary amount of leeway to operate their own grids, though they typically operate fairly; most states have either State Regulatory Commissions or Public Utility Commissions. Responsibilities include:

- Setting service standards for voltage and frequency, among other requirements, for distribution systems;
- Considering and approving proposed power plants; and
- Setting, reviewing, and approving retail rate tariffs

States also have control over the energy fuel mix in their grids; while individual state requirements vary, most have some sort of a Renewable Portfolio Standard (RPS) to increase the share of renewable generation over time. RPSs are treated separately in later sections. Similarly, states each have their own policies toward energy efficiency standards, net metering, and third-party power purchase agreements for solar photovoltaics, among other policies [7–9].

In the late 1990s, many states also experimented with "deregulation" or re-structuring of their electricity sectors to promote retail competition; a short summary of this flirtation is also treated separately in later sections.

Local regulation

In most states, publicly owned utilities (i.e., municipal utilities or rural cooperatives, where they exist) are typically self-governed without too much interference from the state. Local cities and counties also control local transmission and power plant siting (though FERC does have the power -- rarely exercised -- to enforce transmission siting in some cases).

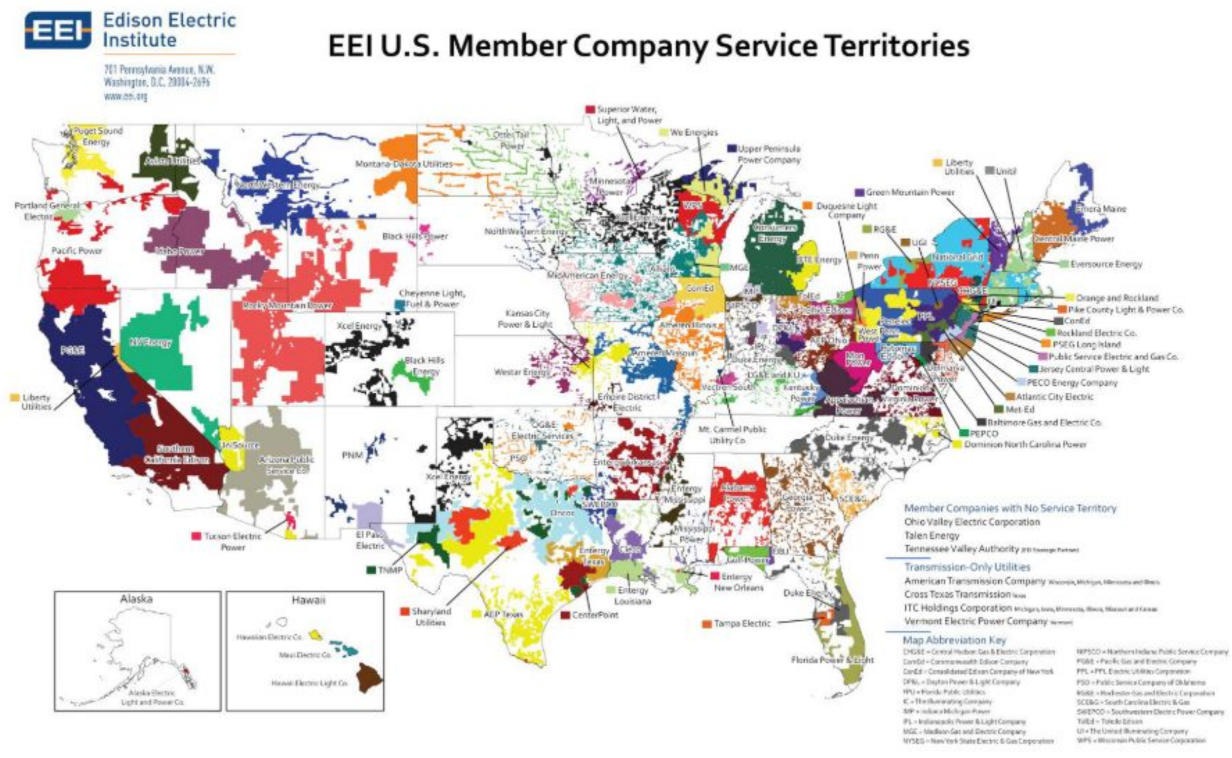
Utilities

Utilities are the organizations that actually provide power to end users. There are several types:

- Privately owned, for-profit Investor-owned utilities (IOUs);
- Cooperatives, which are typically rural, non-profit utilities;
- Federal Power Marketing Administrations, which sell power from federal facilities (mostly hydropower); and
- Municipalities, which are non-profit utilities owned and operated by the city itself.

As areas of the country were electrifying in the late 1800s and early 1900s, local preferences defined which model was chosen. Where trust in local government was low due to corruption, IOUs dominated. Similarly, if there was distrust in corporations, the public typically favored municipal ownership. Cooperatives, which are much more typically rural, developed largely as a result of the 1934 Rural Electrification Act; by that time, urban areas had largely been electrified, while more sparsely populated regions still had not [10].

Figures 5 and 6 are maps with more detail on where these utilities are located.



Produced by Edison Electric Institute's Energy Delivery Group. Data Source: ABB, Velocity Suite 2015. Updated November 2015.

Figure 5. Map of Investor-Owned Utilities (IOUs) who are members of the Edison Electric Institute (from [10])

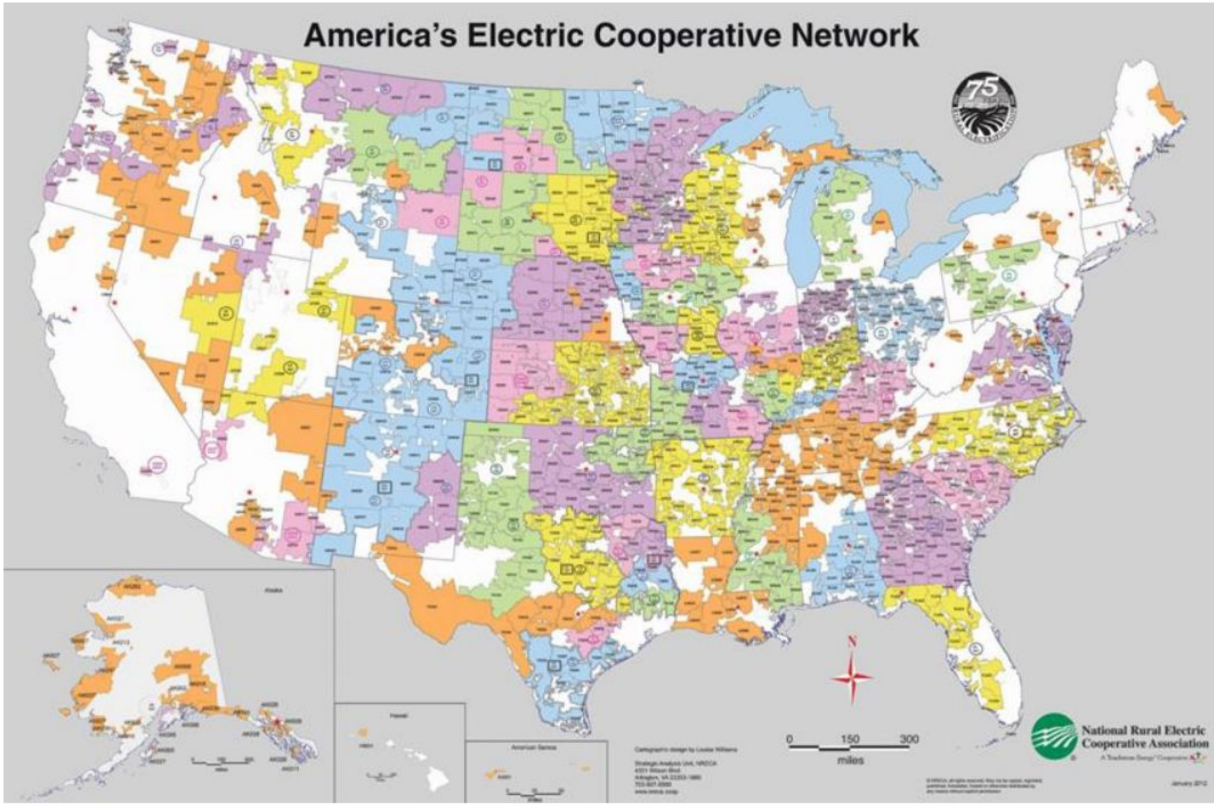


Figure 6. Map of cooperatives (non-profit, community-owned utilities that serve primarily rural areas). [10]

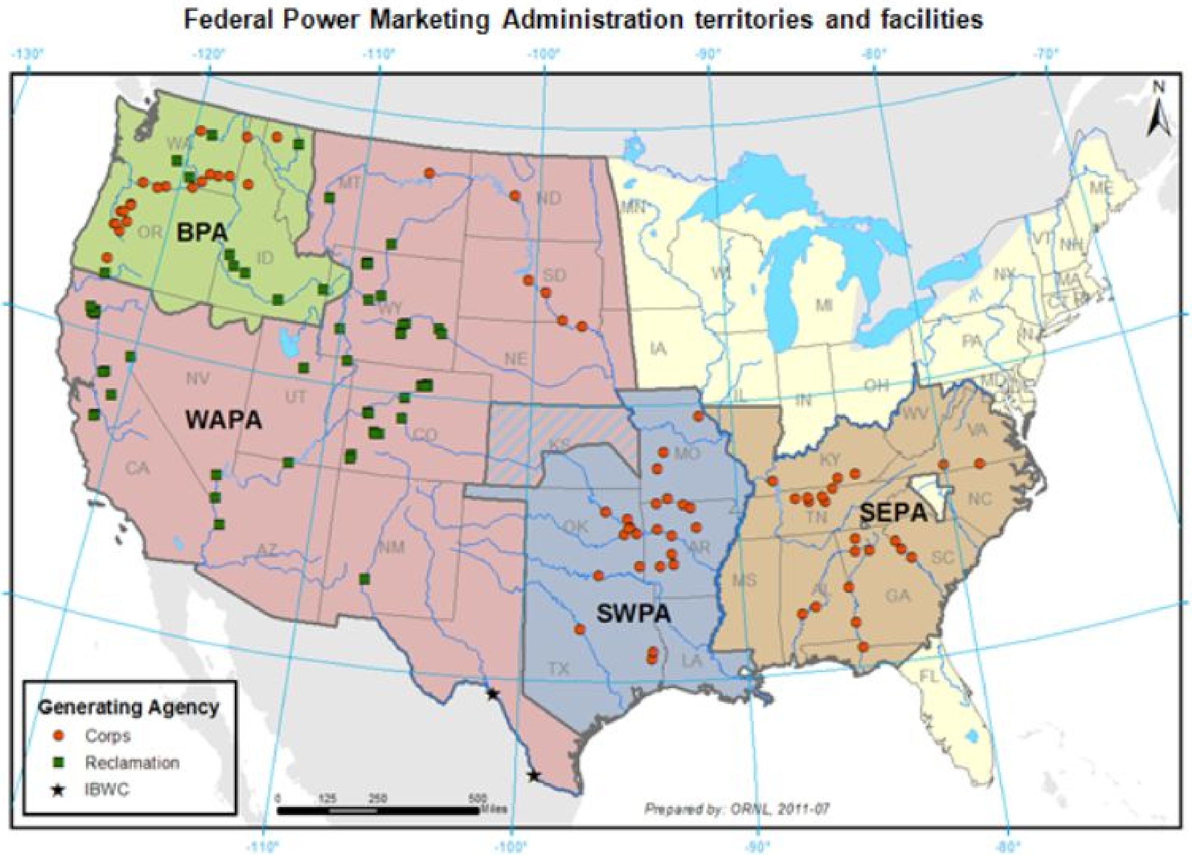


Figure 7. Federal Power Marketing Administrations largely provide power from hydroelectric facilities (from [11]).

Warwick et al. provide a useful statistical summary of the differences in scale and size of IOUs, cooperatives, and municipalities, reproduced in full below (see table 1), as well as a detailed summary of the distribution system overall [10]. Note that IOUs, though they number only a hundred or so -- and they have been consolidating further over the past two decades -- serve approximately 70% of customers [12]. Municipalities and cooperatives are typically much smaller (with the notable exception of the Los Angeles Department of Water and Power (LADWP) which, with nearly 7GW of peak capacity and 4 million residents, is larger than most utilities) [13].

Table 1. Statistics of various utility structures, taken from Warwick 2016 [10]

The table below compares the variance in size, revenue, distribution, customer makeup, and other factors among the different types of utility organizations. IOUs serve by far the most customers, though cooperative utilities in aggregate have a comparable fraction of distribution line miles. The median size of municipal utilities is very small. Despite these characteristic differences, the distribution plant per customer is roughly the same across utility types.

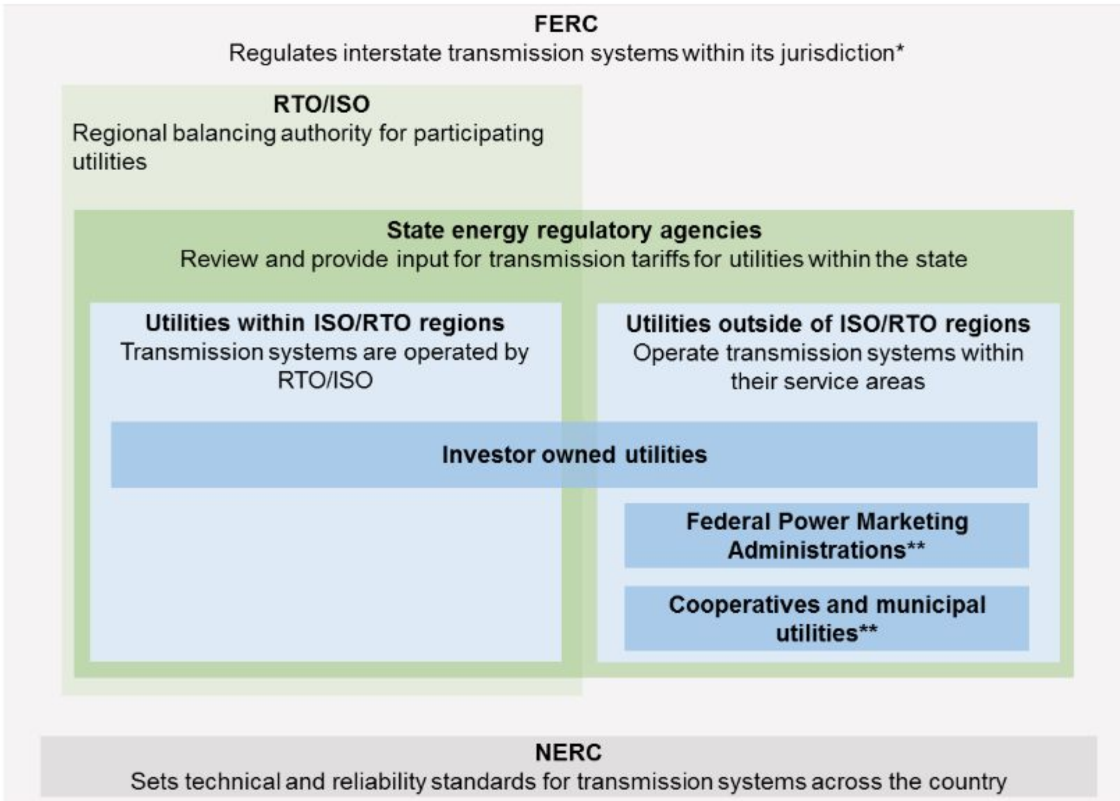
	Investor-Owned Utilities (IOU)	Municipal Utilities	Cooperative Utilities	Total
Total number of customers (millions)	104	21	18.5	144
Total revenue ($ billions)	273	53	40	366
Number of organizations (#)	200	2,000	912	3,112
Size (median number of customers)	400,000	2,000	13,000	
Revenues (percent of total)	75	14	11	
Customers (percent of total)	72	15	12	
KWh sales (percent of total)	73	16	11	
Sales (billion kWh)				
Residential	992	212	239	1,443
Commercial	1,057	210	84	1,351
Industrial	659	148	90	897
Total	2,708	570	413	3,691
Fraction of distribution line miles (percent)	50	7	43	100
Customers per mile of line (density)	34	48	7.4	
Revenue ($/per mile of line)	75,500	113,000	15,000	
Distribution plant per customer ($ per capita)	$2,798	$2,740 [(a)]	$3,290	
Assets ($ billions)	870	260 [(a)]	140	1,270 [(a)]
Equity ($ billions)	280	76 [(a)]	42	398 [(a)]
Equity (percent)	32	32 [(a)]	30	

(a) Estimate

Acronyms: KWh = kilowatt-hours.

Overview

Chernyakhosvkiy et al. provide a useful chart encapsulating the overlapping regulatory responsibility for each of these organizations [14].



* FERC jurisdiction does not apply to the Texas Interconnection, Hawaii, and Alaska.
**Federal Power Marketing Administrations, cooperatives, and municipal utilities are exempt from general FERC regulation.
Some cooperatives and municipal utilities are outside of state regulatory agencies' jurisdiction.

Figure 8. Regulatory responsibility for the grid from federal to local levels (from [2])

Timeline of major regulatory milestones

Several excellent sources provide overviews of U.S. electricity regulation. In order of increasing comprehensiveness: NREL's *US Laws and Regulations for Renewable Energy Grid Interconnections;* WIlrich's *Modernizing America's Electricity Infrastructure*, and Isser's *Electricity Restructuring in the United States [12,14,15]*.

The early twentieth century, in the run-up to the Great Depression, saw a number of strong trends: electric utilities all through the United States were given monopoly status; a vast increase in electrification took place even as prices plummeted 85% from their levels in the 1890s; and there was an extraordinary increase in the amount of electricity being used by the public, growing at an annual rate of 12% per year. And while utilities increased in size through an expanding customer base, they also opted for a number of mergers and acquisitions to continue benefiting from economies of scale. The early twentieth century also saw the development and expansion of holding companies, which could own and oversee not only a number of utilities across multiple states but also subsidiaries specializing in engineering or equipment manufacturing. (Holding companies also employed extraordinary financial leverage; during the Great Depression, one holding company -- Middle West Utilities Company -- went into receivership in large part because of its extraordinary 90% leverage.) By 1935, eight holding companies controlled 73% of America's investor-owned utilities [12]; and due to their perceived abuses, were no longer very popular with the public.

Federal Power Act and Public Utility Holding Company Act (1935)

As part of the New Deal measures after the Great Depression, the Public Utility Holding Company Act (PUHCA) required all electric utility holding companies to register with the newly-formed Securities and Exchange Commission (SEC), which began to strictly oversee and regulate holding companies. Many of these holding companies, in order to avoid onerous regulation, decided to voluntarily divest and contain themselves to a single state, in order to simplify their structure. State-level regulation, small IOUs operating entirely within a single state, and municipal utilities quickly became the new normal for ownership structures [12].

At about the same time, the Federal Power Act (which had originally been enacted as the Federal Water Power Act in 1920 to coordinate hydroelectric power development) was rewritten to give the Federal Power Commission (the immediate precursor to FERC) explicit oversight of all interstate electricity transmission and wholesale energy trading [12,16].

Rural Electrification Act (1936)

By 1936, cities had been mostly electrified; but rural areas still were largely unconnected to a grid. The Rural Electrification Act was signed as both an infrastructure project to provide jobs to the vast numbers of unemployed as well as an initiative to bring power to rural areas. Electric cooperatives sprang up as a result; and as a class of utilities, they still contain the vast majority of geographic area within the United States, even if they're providing a much smaller fraction of its electricity (under 5%, as of 2015) [12,17].

Public Utilities Regulatory Policy Act (1978)

The Public Utilities Regulatory Policy Act (PURPA) was passed in 1978 as a response to the 1970s energy crisis, and represented the first injection of competition into utility monopolies. PURPA incentivized energy efficiency (by, for example, eliminating the promotional rate structures where electricity would cost less with increasing usage), and it also obligated utilities to purchase power from "qualifying facilities" at the utilities' avoided cost. These "qualifying facilities" fell into two categories: small power production facilities, which FERC defines as "a generating facility of 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources"; and cogeneration facilities: "a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy". As such, PURPA represents one of the first major regulatory pushes by the United States to bring renewable energy to the fore [12,18,19].

Energy Policy Act (1992)

The Energy Policy Act of 1992 sought to increase clean energy use and further improve energy efficiency in the United States; it also amended PUHCA to create a new class of “exempt wholesale generators” (EWGs). EWGs could be power plants of any size, using any primary energy resource, and, most significantly for power companies, located anywhere. PUHCA defined whether or not a utility was in a single state by how much of its revenue came from that state; “exempt” meant that the power plants’ revenue did not count towards that requirement. Therefore, utilities purchasing power from these EWGs would not fall foul of the requirements of PUHCA that had driven so many to become single-state enterprises in order to avoid intense federal oversight from the SEC. At the same time, however, FERC would be given the responsibility for ensuring that wholesale power markets were competitive [20,21].

FERC regulatory orders (1996 - present)

Also in 1992, FERC began to take its mandate as regulation for the electricity industry much more seriously, issuing a series of orders (starting with orders 888 and 889 in 1996) with the cumulative effect of vastly increasing competition at the wholesale level. FERC’s orders -- especially those related to ISOs/RTOs, interconnections and open-access transmission -- represent the most relevant policy constraints on U.S. wholesale electricity markets.

A full list of FERC’s orders is on its website [22]; a brief overview is included below.

Orders 888/889 (1996)

By 1996, FERC had concluded that public utilities were using their market power to throttle competition from independent power producers. In response, FERC issued orders 888 and 889, which:

- Codified open access transmission tariffs, requiring utilities to separate transmission and sales of electricity;
- Established the Open Access Same-Time Information System (OASIS);
- Encouraged (but did not require) the formation of Independent System Operators (ISOs) as a way to manage power flows most efficiently; and
- Defined the original six ancillary services required to ensure reliability ([23] p 151).

Order 2000 (1999)

In 1999, FERC identified that ISOs were still seeing engineering and economic inefficiencies, and so FERC defined Regional Transmission Organizations (RTOs) in Order 2000. RTOs were required to have market monitoring and long-term planning, and required all transmission-owning public utilities either to file an RTO proposal or an explanation of why they weren’t participating. (Since then, however, and especially with the passing of additional later orders, ISO and RTO roles have largely converged [23].)

Orders 2003, 661, 2006, 792 (2003, 2005, 2013)

These orders provided standard interconnection procedures for large generators greater than 20 MW (orders 2003 and 661) as well as for smaller generators under 20 MW (2006 and 792). Overall, they reduced the timeframe and cost of interconnection for renewable energy generators, as well as mandating additional technical requirements (for example, by requiring that wind generation facilities be able to “ride through” low voltages) [2].

Order 670 (2006)

After the Energy Policy Act of 2005 gave FERC the explicit authority to prohibit energy market manipulation, order 670 was written as the legislation forbidding it.

Orders 890, 1000 (2007, 2011)

In 2007, FERC re-committed itself to the principle of open-access transmission, and issued order 890 to remedy undue discrimination, increase transparency, and provide greater specificity in certain areas of transmission: namely, calculations of available transfer capacity, conditional firm service, and balancing services. Utilities were also required to coordinate with interconnected systems, as well as to plan for appropriate transmission capacity and cost allocation in the future [23].

Order 745 (2011)

FERC required that demand response capabilities be treated like a power plant, and that demand response providers be paid locational marginal pricing (LMP) rates for that service. This order was immediately contested as federal overreach; but the Supreme Court sided with FERC in 2016, upholding and affirming the federal role in supporting demand response [24].

Order 764 (2012)

This order required transmission owners to provide 15-minute scheduling windows, which allowed generators using renewable energy (especially wind and solar) to better respond to resource variability in their power delivery schedules.

Orders 841, 845 (2018)

With orders 841 and 845, FERC opened up the wholesale market to storage. The orders required tariff revision specifically to account for electric storage resources and, while requiring new interconnections to have frequency response capabilities, specifically exempted energy storage from having to meet all of those requirements.

Order 848 (2018)

With Order 848, FERC sought to address cyber-security considerations before they become seriously problematic. Order 848 requires NERC to augment its reliability standards to include mandatory cyber-security incident reporting.

Energy Policy Act (2005)

To the great delight of utilities everywhere, the Energy Policy Act of 2005 repealed PUHCA. This repeal meant that, for the first time since 1938, fully diversified companies were permitted to buy and control far-flung utility networks across the nation [23]. The act also terminated long-term PURPA contracts and abandoned the "avoided cost" rate principle, along with providing tax incentives for transmission system improvements. By forcing out uneconomical projects, it further increased competition in wholesale power markets [2]. Additionally -- coming only a few years after the Western Energy Crisis -- it also explicitly mandated that FERC oversee energy markets to prevent their manipulation (FERC wrote order 670 to implement that requirement). The act also established a one-year 30% tax credit for investments in solar energy property, which ended up being extended for over a decade.

American Recovery and Reinvestment Act (2009)

Though not truly a regulatory milestone as such, the American Recovery and Reinvestment Act served to accelerate the transition of the U.S grid toward being a true "smart grid", and provided several billion dollars of funding to do so. For a brief summary, see report 1.5 or http://www.smartgrid.gov/.

Restructuring and "deregulation"

The competition that was happening at the generation levels in the 80s and 90s (encouraged by PURPA, the Energy Policy Act of 1992, and FERC) was leading IOUs to divest from generation ownership: the IOU share of generation went from 71% in 1996 to 36% in 2016. It was, generally, also leading to lower wholesale prices for electricity. Retail electricity prices, however, were increasing in many states. Nuclear power plants were often slower to construct and vastly more expensive than originally budgeted; and power plants were often abandoned mid-construction as the business cases no longer made sense. (In Washington's Public Power Supply alone, there were $13 billion in failed investments [25].) These costs eventually were passed along to ratepayers. At the same time, the oil embargo was causing some wholesale prices to rise, and so great pressure began to be placed on state-level regulators to control the costs that customers were seeing.

In general, states grew interested in taking the savings that were being observed from wholesale competition and passing those savings along to ratepayers who were seeing higher prices. These typically took one of two forms:

- Allowing for independent retailers, who competed directly for customers; or
- Creating a "wholesale club", in which utilities would exercise market power to negotiate in the wholesale market on behalf of customers.

In the late 1990s, states in the West and in the Northeast pursued restructuring. After the California electricity crisis in 2000 and 2001, however, restructuring efforts by states almost entirely ceased.

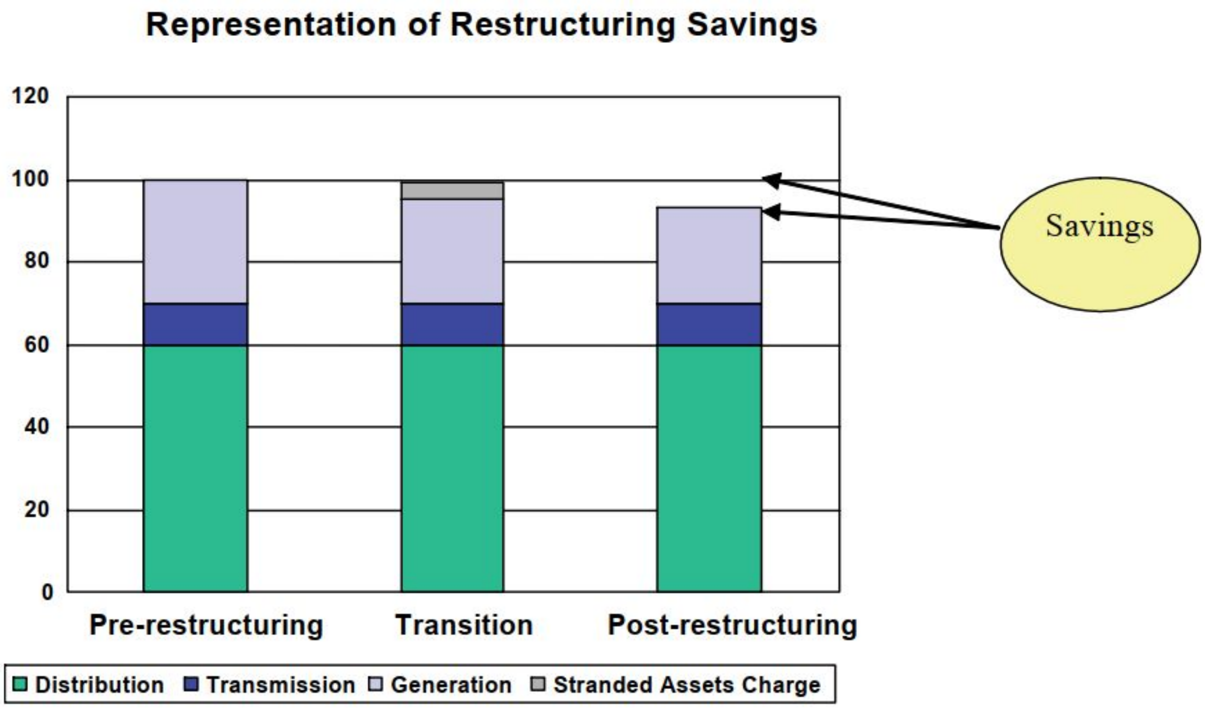


Figure 9. Fagan’s representation of the goals of restructuring. While savings would be relatively small as a percentage of total cost, it still represented billions of dollars of savings by end-users [25].

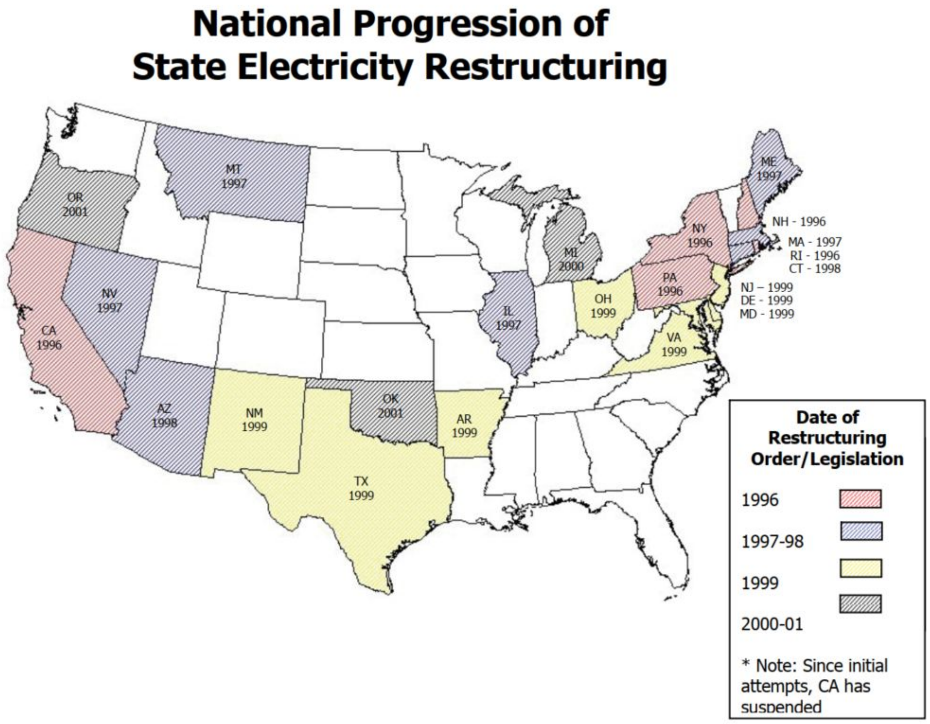


Figure 10. Which states pursued restructuring, and when they began to pursue it. After California's restructuring debacle, states that had not yet restructured chose not to (figure from [25]).

The curious case of California

California, in 2000 and 2001, underwent an extraordinary electricity crisis: wholesale prices for electricity shot up by a factor of ten while not enough power could actually be delivered to customers. The combination led to widespread rolling blackouts, required the state of California to bail out utilities to the tune of several billion dollars over only a few months, and ultimately led to the recall of then-Governor Gray Davis in 2003 [26,27]. (Note that Joskow's review was published before the misdeeds of Enron came to light; however, it still points to a lot of the underlying susceptibilities in the market.)

In 1996, California passed AB1890, which allowed for retail customer choice (i.e., customers could choose their electricity retailer directly). Customers who didn't want or care to switch, however, could still retain their original service by default. At the same time, retail rates were dropped by 10% and then frozen for several years (scheduled until March of 2002). AB1890 also included incentives for utilities to further divest from power generation, and created both the CAISO and a power exchange ("PX") to manage both day-ahead and real-time markets.

And while the first two years of restructuring saw no major price spikes, a combination of poor design, bad luck, and tight markets saw a two-phase meltdown over the summer of 2000 and in the winter and spring of 2001 (see figure 11).

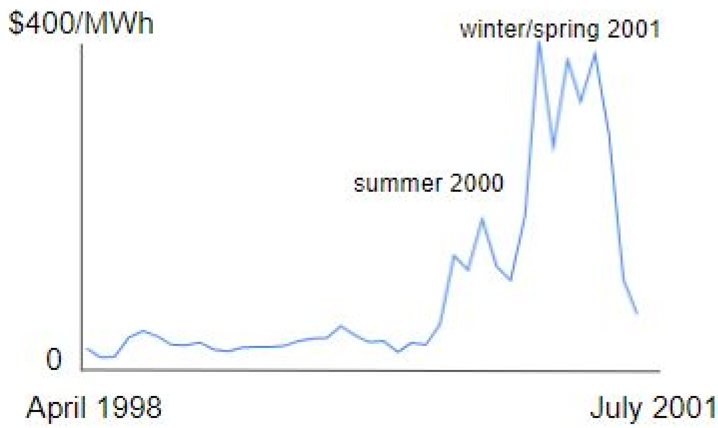


Figure 11. Wholesale electricity prices during the California electricity crisis; data from [26].

The poor design was baked in from the beginning. Freezing retail rates at 10% below their current levels for so long meant that few end-users cared to switch away from their default utility service. (In fact, 97% of customers representing 88% of electrical demand chose to remain with their default provider.) Similarly, there was no escape valve for utilities in the event -- presumed to be extraordinarily unlikely at the time -- that wholesale prices ended up above retail rates. At the same time, there was an excessive reliance on the more volatile spot market instead of on owned capacity or longer-term contracts; Weare notes that fully 30% of generation was being purchased on the spot market ([28] p 40).

Both Joskow in [26] and Weare in [28] point to several different external causes all leading toward the crisis:

- There had been a larger-than-expected growth in demand for electricity outside the state in the run-up to 2000, reducing the availability of imports on which California typically relied;
- Hot summer weather in 2000 and a drought in the Northwest further reduced the availability of electrical imports;
- Nitric/nitrous oxide (NOx) emissions prices stepped up, which increased the operating costs of power plants;
- Natural gas prices were unexpectedly increasing, and spiked by 10x in the winter of 2001;
- A tight market with no elasticity meant that all suppliers had market power, and some suppliers (most notably Enron) abused their positions to raise prices to record levels.

These causes interplayed to compound problems even further. The hot summer weather and inability to import power in 2000 led to power plants deferring maintenance, so that in the winter of 2000, an unexpectedly high number of power plants -- representing a full third of California's generating capacity -- were offline. With comparatively few generators and an extraordinarily inelastic market (after all, the 97% of customers who had stuck with their default utility had zero incentive to change their behavior while their rates were frozen, even if they had been paying close attention to wholesale price signals) many unscrupulous electricity providers could easily withhold generation to drive prices even higher. Enron is by far the most famous of the unscrupulous profiteers, though several other companies were also implicated during investigations by FERC [29].

And while the crisis was widely recognized by the summer of 2000, it extended for so long because of a series of regulatory missteps by both state regulators and FERC. FERC, though it had recognized that wholesale prices were quite high, neglected to act swiftly or aggressively, leaving California to address the crisis alone -- which they attempted to do while explicitly avoiding raising retail prices. Mutual mistrust between the two regulatory agencies led each to wait for months before acting; it was only in the spring of 2001 that the State of California and FERC both finally relented by raising retail prices and imposing wholesale price caps, respectively ([28] p46).

The crisis was eventually resolved by additional capacity coming online in the summer of 2001, along with a reduction in natural gas prices to historical averages. Immediately, however, restructuring stopped not only in California, but in virtually every other state that had been considering implementing something similar. (Note, however, that restructuring efforts that had already taken place, such as in New England, were not reversed.)

For further reading on the origins, timelines, and results of the crisis, the reader is encouraged to review: Joskow's *California Electricity Crisis*; Weare's *The California Electricity Crisis: Causes and Policy Options*; and FERC's *The Western Energy Crisis, the Enron Bankruptcy, and FERC's Response [26,28,29]*.

Renewable Portfolio Standards

Renewable Portfolio Standards (RPSs) are independent, state-level policy efforts with a common goal: to increase the relative sales of electricity derived from renewable sources. Beyond that general definition, however, each state is effectively its own renewables market.

RPS history and performance

Renewable portfolio standards are often considered to have started in 1983, when Iowa mandated that its two IOUs must contract for 105 MW of renewable generation [30]. Only in the late 1990s and early 2000s, however, did states begin to adopt renewable portfolio standards en masse (see figure 12). As renewable portfolio standards are being met -- and they're being met much faster than expected -- they're also being revised and made even more ambitious. As of 2018, for example, California explicitly added a goal of 100% carbon-free electricity by 2045 [31].

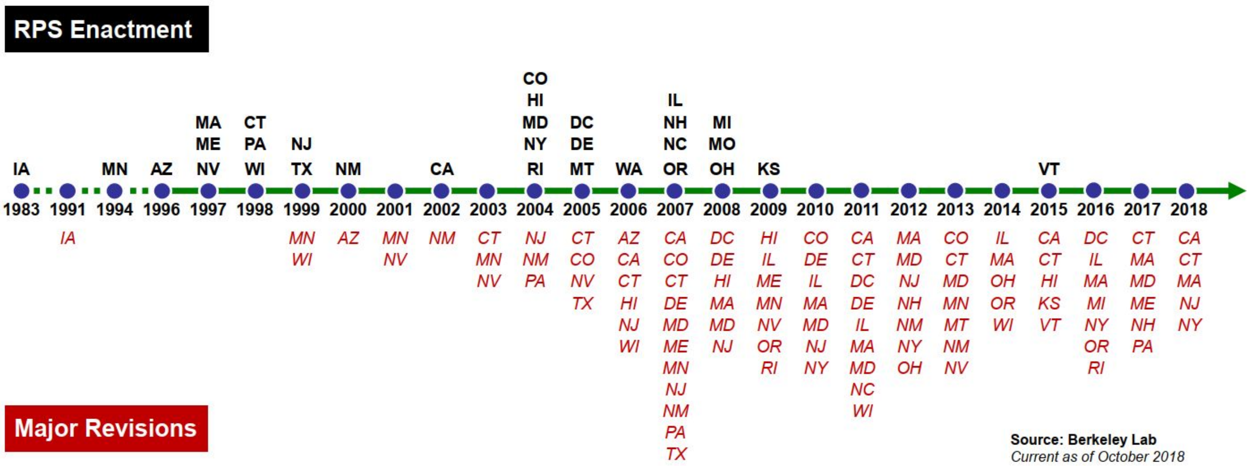


Figure 12. A brief timeline of when states enacted or made major revisions to their Renewable Portfolio Standards (from [31]).

As of October 2018, there are 29 states that have renewable portfolio standard (along with Washington, D.C. and 3 territories), while an additional 8 states have non-binding renewable portfolio goals (see figure 13).

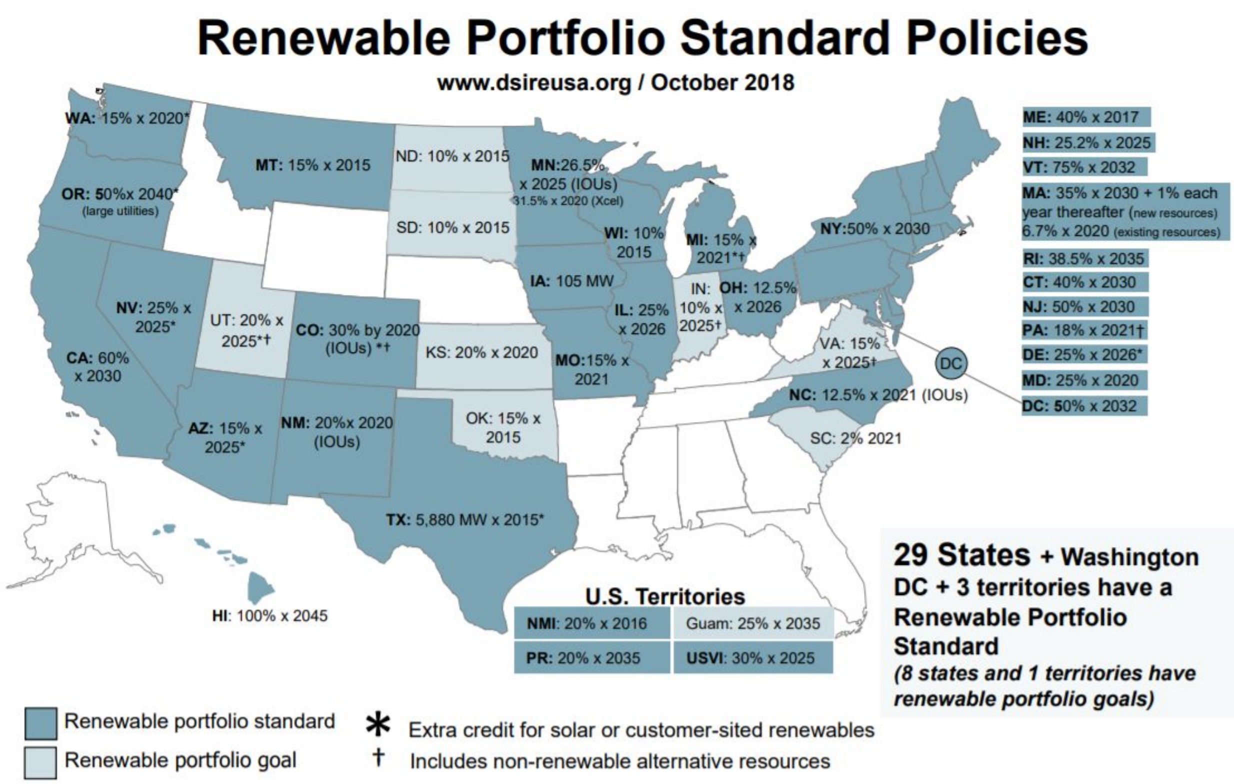


Figure 13. Map of states with Renewable Portfolio Standards or goals (from [32]).

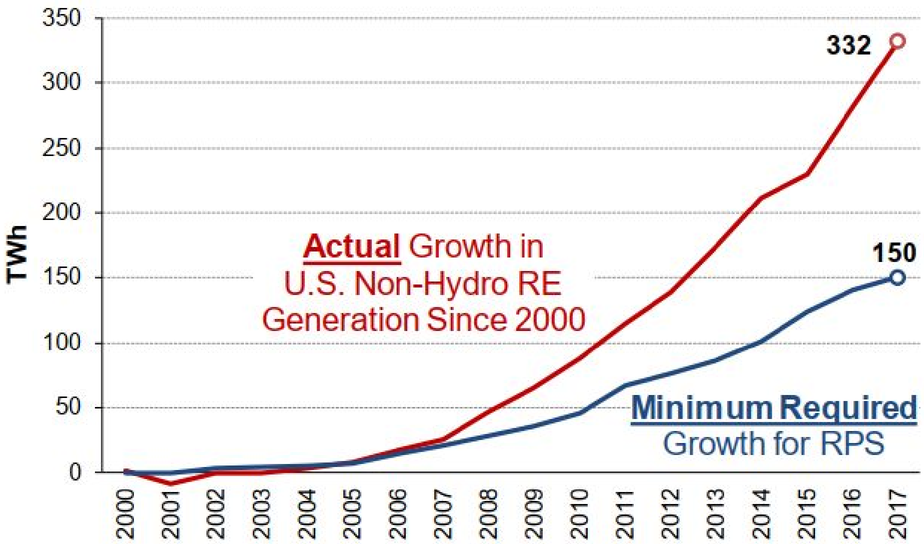


Figure 14. Renewable energy production generated from 2000 - 2017 is over and above that which otherwise would have been required by Renewable Portfolio Standards alone (from [31]).

Beyond the similarities that 1) most states have renewable portfolio standards and 2) many states are making them ever-more ambitious over time, however, renewable portfolio standards vary quite widely; Fischlein and Smith provide a helpful overview. For example: in some states, advanced fossil fuels, nuclear energy, energy efficiency, or distributed energy are considered “renewable” (table 2) [33].

Table 2. Definitions of what is considered “renewable energy” vary widely from state to state (from [33]).

Resource	Eligible in
Advanced fossil or nuclear	IL, OH, PA, UT
Energy efficiency	CO, CT, HI, NC, NV, OH, PA, UT
Distributed energy	AZ, CA, CO, DE, KS, NC, NV, OH, PA, UT

Renewable energy credits

States tend to agree that renewable energy counts as renewable energy wherever it’s created, and so generators or retailers are typically allowed to decide whether they’d rather invest in their own projects or purchase renewable energy credits. Renewable Energy Credits (RECs) are certificates of proof that one MWh of electricity was generated by a renewable-energy source, and these can be sold either “bundled” (in conjunction with the physical energy that was generated) or “unbundled” (sold separately). Note that RECs need not be associated with an RPS: a robust voluntary market also exists, but it represents only about about 26% of all U.S.

renewable energy sales (excluding large hydropower). Compliance markets represent the majority of RECs sold, at approximately 57% of sales in 2017 [34].

Incentivizing particular technologies

States will often advantage particular desired outcomes by adding “credit multipliers” for certain activities. For example, Colorado, though it allows for the purchasing of unbundled renewable energy credits, offered a 25% credit multiplier for the development of in-state renewable energy in 2013. Similarly, Texas offered a multiplier for in-state, non-wind renewables (Texas has had a long history of developing its plentiful wind resources); and Washington is focused on the development of distributed energy more generally [33].

Enforcing compliance

State-level strategies also abound in terms of enforcing these standards. As of 2013, Fischlein et al. recorded that:

- 27 states issued fines, which don’t relieve the utility of the obligation to provide renewable energy;
- 17 states allowed for “alternative compliance payments”, which utilities can pay instead of purchasing or generating renewable energy (effectively putting a maximum price on meeting the requirement);
- 20 states had some sort of a financial safety valve to prevent excessive cost impacts (due to, for example, price spikes); and
- Several states had waivers (though they’re rarely used, if ever) in case customer prices increased too much.

In 2017, the total cost of compliance across all states with RPSs was approximately $4.1 billion; as a percentage of the average retail electricity bill, this typically ranged from 0.6% to 4%, depending on the state (Massachusetts was a notable exception, where compliance was estimated to cost nearly 10% of the average retail electricity bill) [31].

Overall, RPSs are considered largely successful, and are a key driver for increasing renewables penetration throughout the country. Note, however, that at least as responsible -- if not more so -- is the drastically falling cost of renewables. States have clearly indicated, through the use of alternative compliance payments, caps, or other financial safety valves, that they are willing to pursue these policies only if the costs are not too high. The fact that states are continually increasing their targets over time is due in no small part to the fact that renewable energy is cost-competitive on its own terms.

Electricity markets

Much regulation in the United States has been focused particularly on the introduction of competition into the electric sector. In the traditional model of utilities, a single vertically-integrated entity was responsible for electricity production and distribution from generation through transmission, distribution, and retail (see figure 15, left). Since the late 1970s, however, federal regulation has injected a lot of competition in the wholesale market (figure 15, right). This system-level change has led to the development of a number of sophisticated market structures that are able to successfully balance three distinct sets of requirements: instantaneous balancing of generation and load; physical constraints on the transmission system (specifically, Kirchoff's voltage laws); and straight-forward, timely compensation among all the participants.

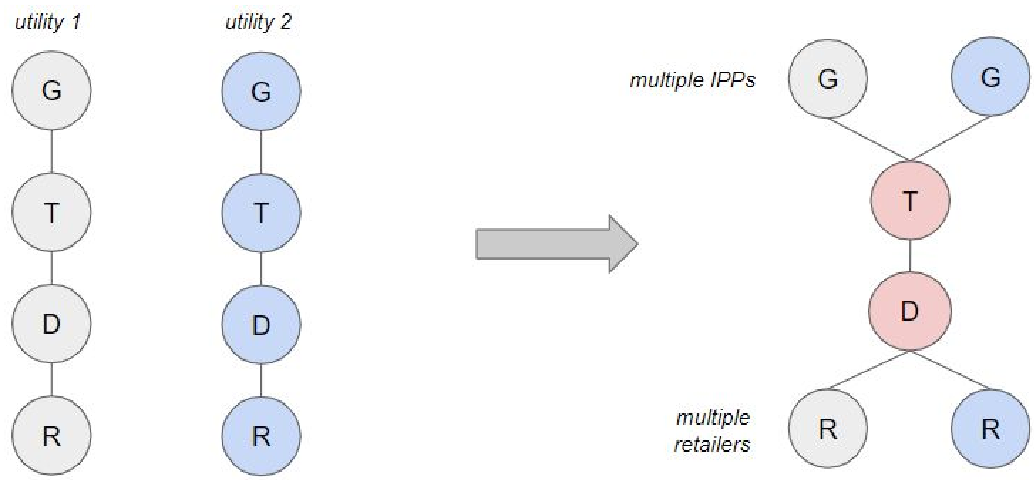


Figure 15. *G, T, D, and R* stand for Generation, Transmission, Distribution, and Retail, respectively. Over the past fifty years, electricity delivery has been slowly migrating from the model on the left -- vertically integrated utilities responsible for all aspects of power delivery -- ito the model on the right, where wires are the only "natural monopoly", and competition develops in both power generation and retail.

For a high-level overview of wholesale electricity markets, retail markets, capacity markets, and an explanation on one of the most common pricing methodologies (the locational marginal price, or LMP), see Ransil's paper, Report 1.1: Energy Pricing.

Market actors

While the particulars of each market differs, there are typically a few consistent major players; these are described well by both Lopes and Kirschen et al. in their books [35,36]. These actors include:

- *Vertically integrated utilities*, which own and operate their own generation, transmission, and distribution assets;
- *Generation companies*, which own and operate their own power plants (also known as Independent Power Producers, or IPPs);
- *Distribution companies*, which own and operate distribution networks;

- *Retailers*, which buy electricity in wholesale markets and re-sell it to customers (who either are not allowed to participate in wholesale markets or do not want to);
- *Consumers,* who, if large enough, may purchase power directly from the wholesale market (and not via a retailer);
- *Market operators*, who are typically for-profit entities running the computer systems matching bids and offers and then taking care of the settlement process afterward;
- *Independent System Operators*, which maintain the stability and operational reliability of the entire power system (and are typically non-profit and ideally neutral and independent); and
- *Transmission companies*, which own transmission assets and operate them according to the ISO rules.

Additional combinations, variations, and flavors of these entities may also exist (for example, transmission system operators, which combine the functions of an ISO and a transmission company) depending on the particular market.

Wholesale U.S. markets

An introduction to the basics of wholesale market design and operation is in Ransil's report 1.1: Energy Pricing. Below, a few areas are expanded upon in more detail.

Note that not all areas of the United States are served by wholesale markets like those run by ISOs. Some of those ignored areas, however, are exploring the utility of creating a market anyway. In a 2013 study done by the Pacific Northwest National Laboratory (PNNL), authors estimated that benefits would likely be in the range of $70 million - $80 million annually by, among other things, requiring fewer reserves to be maintained by any given balancing authority [37].

Ancillary services

FERC defines "ancillary services" as

> *Those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system [...].* [38]

As such, there are many services that could count as "ancillary" services, though FERC originally listed six in order 888 [39]:

- Scheduling, System Control and Dispatch Service;
- Reactive Supply and Voltage Control from Generation Sources Service;
- Regulation and Frequency Response Service;
- Energy Imbalance Service;
- Operating Reserve - Spinning Reserve Service; and

- Operating Reserve - Supplemental Reserve Service.

These can most easily be differentiated in terms of the required response times, as well as the distinction between whether these are “normal” operations or “contingency” operations -- i.e., either an expected part of daily operation of the grid or a response required because of equipment malfunction, respectively (see figure 16). Each is described in more detail below. For further reading, or a more in-depth explanation of each service, the reader is encouraged to review [40–42].

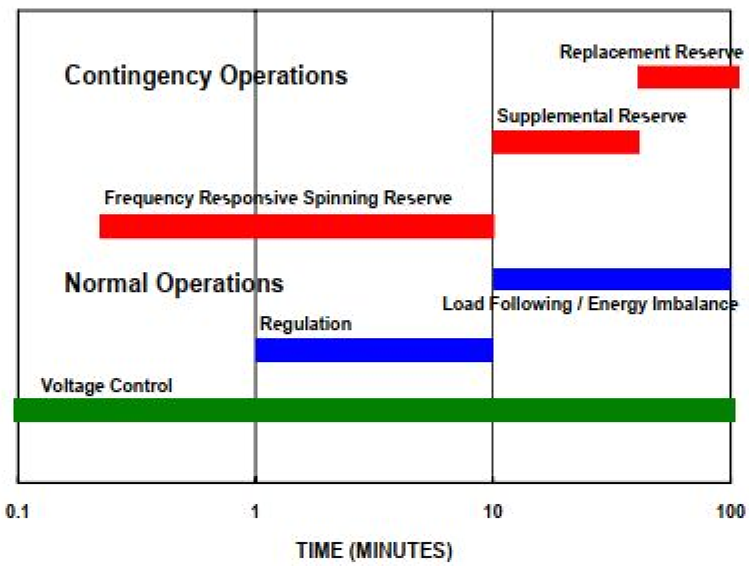


Figure 16. Various ancillary services as a function of how quickly they must respond, as well as whether these services are part of “normal operations” or “contingency operations” (from [40]).

For more information on the particulars of each U.S. market -- that is, the specific products available for purchase in CAISO, ERCOT, PJM, etc. -- see Zhou et al’s survey [43].

Continuous regulation in normal operation

Normal operation includes matching two levels of variation: first, the overarching load profile of the day, and then deviations from that overarching load profile.

The load profile is typically a strong function of the time of day. In most places, electricity usage tends to peak in the late afternoon and early evening, while dropping to a minimum late at night. Load is also a strong function of the weather: energy usage will be higher on particularly cold or particularly warm days, as either heaters or air conditioners use more energy. See figure 17 for a sample breakdown of an overall daily load profile.

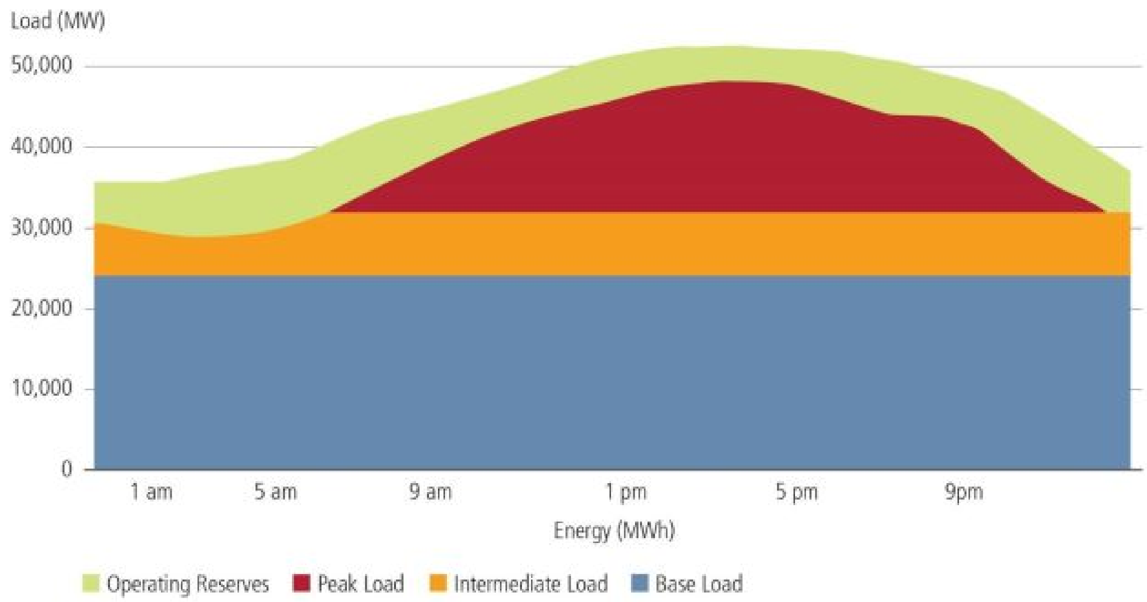


Figure 17. A typical demand curve over the course of twenty-four hours, divided into its constituent parts: “base load”, which is the minimum expected demand on the grid; “intermediate load”, which is on most of the time and ramps very slowly, if at all; and “peak load”, which requires quick response times from power plants. “Operating reserves” are those required in case of contingencies. (Image from [44].)

“Load following”/”energy imbalance” describes the matching process of total power in the system with total demand (represented in figure 17 by the sums of base, intermediate, and peak loads). Note that these differences are in the thousands and tens of thousands of MW, and represent dozens of power plants that are being turned on and ramped to full power (and then off again).

“Regulation” is the more precise matching of minute-to-minute variation of load to demand. It requires online generation, storage, or load that can ramp automatically and extraordinarily quickly (on the order of MW/min) in response to signals from the balancing authority (see figure 18). Note that regulation is only on the order of tens of MW, and, importantly, should average out to zero. Too much deviation one way or the other, though, will cause the grid’s baseline frequency to drift out of specification. NERC employs two standards (Control Performance Standards 1 and 2, or CPS1 and CPS2) to ensure that balancing authorities are performing appropriately. (For more information on CPS1 and CPS2, see NERC’s guide on *Balancing and Frequency Control* [45]).

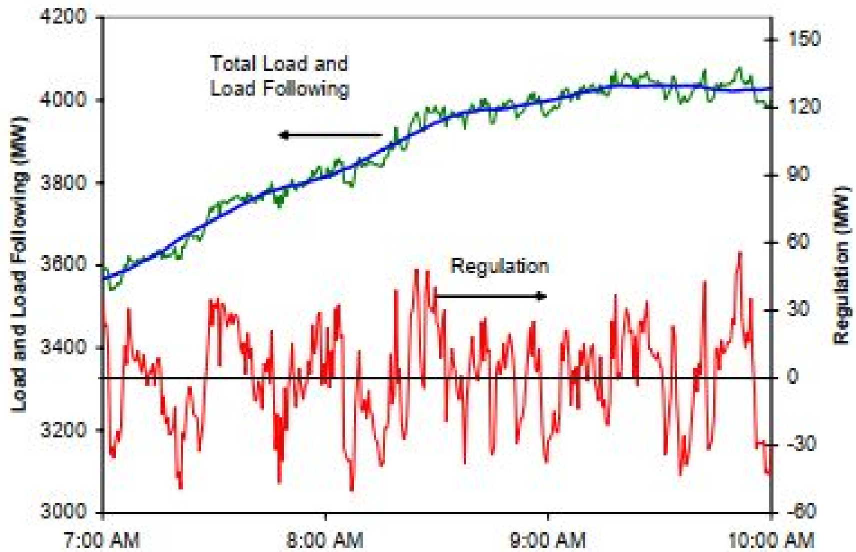


Figure 18. A more detailed view of the difference between load following and regulation. Load-following resources will slowly ramp, following the moving average of precise loads, while regulation resources will quickly match to the smaller deviations from that moving average. (From [40])

Both load-following and regulation reserves are procured in the day-ahead and real-time markets; figure 19 shows typical prices in California for these capabilities. Note that regulation -- requiring the fastest response -- is the most expensive; generation that is slower to respond ("replacement reserves") cannot command as high a price.

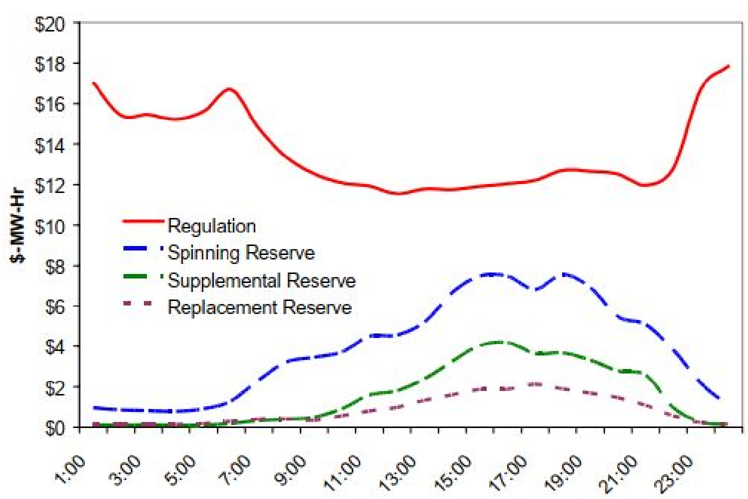


Figure 19. CAISO average hourly prices (2002) for various types of ancillary services (from [40]).

Contingency response

Occasionally, equipment failures lead to unexpected, steep drops in power output, recognizable as a drop in frequency on the system. To keep the system functioning nominally, instantaneous contingency reserves (“frequency responsive spinning reserve”, in figure 16) are employed. These provide frequency support until supplemental and/or replacement reserves can come online to replace the lost power (see figures 20 and 21). Depending on the ISO, instantaneous and contingency services may be purchased on the day-ahead and real-time markets [43].

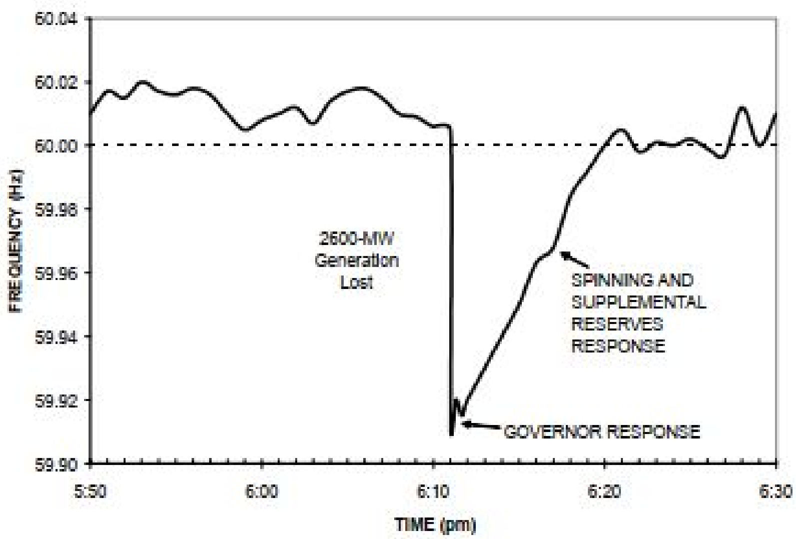


Figure 20. The “governor response” represents instantaneous contingency reserves kicking in to arrest the fall in frequency on the grid; spinning and supplemental reserves then kick in to bring the grid frequency back to nominal (from [40]).

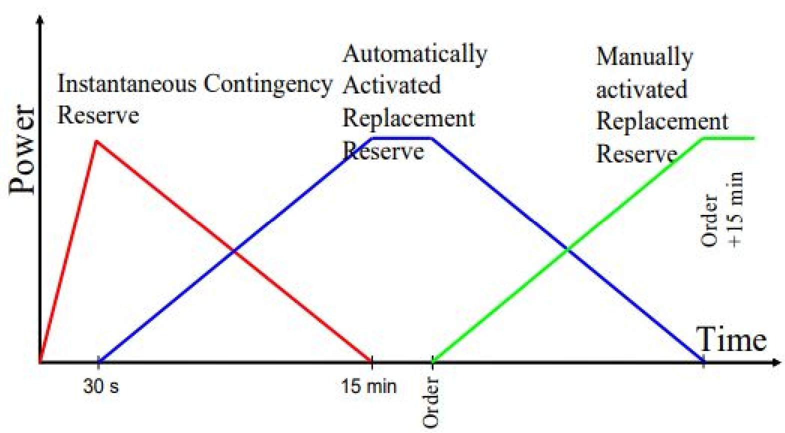


Figure 21. Another representation of when different resources react to arrest and respond to a disturbance on the grid (from [42]).

Other services

Other services that are not yet separate parts of the ancillary services market, but are nevertheless important parts of keeping the grid functioning, include volt/VAR control and “black start” capabilities.

Voltage support

Voltage support functionality is intimately related with the volt-ampere reactive (VAR), a unit of “apparent” power that results from the current and voltage being slightly out of phase with each other. VARs support the magnetic and electric fields found in inductive and capacitive loads (of which there are plenty on the grid). A detailed discussion of VARs is out of the scope of this report; however, they have several salient characteristics that are relevant here:

- They don’t travel well across long transmission lines;
- They can be created and consumed by both generation and load; and
- Reactive power sources can be both “static” (often on transmission lines) or “dynamic” (often provided by generators).

Without strong guidance from FERC, different ISOs have different methods of paying for voltage support, but there have been relatively few instances of using markets for compensation. The Southwest Power Pool, for example, requires all generators to operate within a standard range of 0.95 leading to 0.95 lagging (both measures of power factor) and to supply it at SPP’s or the balancing authority’s behest. Should additional reactive power be required, SPP will pay for the amount of additional reactive power outside of the range 0.95 leading to 0.95 lagging at a given rate ($2.26/MVAr hour as of 2014) once a month. The PJM Interconnection, on the other hand, pays for reactive power according to methodology ascribed by the American Electric Power Company. PJM also offers make-whole payments based on start-up costs or opportunity costs when generators are required to supply additional reactive power at the expense of real power [46].

For more information on reactive power and payments, the reader is directed to FERC’s reports *Principles for Efficient and Reliable Reactive Power Supply and Consumption* and *Payment for Reactive Power* [46,47].

Blackstart capabilities

Under particularly severe disturbances to the grid, many generators may shut down and have no access to power from the grid. In that case, several sets of resources are required: generation units that can start themselves without an external electricity source; additional units that can quickly return to service after off-site power has been restored; and transmission and systems equipment that can communicate and operate without grid power. [48]. As with voltage support, individual ISOs have their own strategies for ensuring blackstart capabilities, and their requirements are described in their individual tariffs. CAISO, for example, contracts directly with individual generators to provide blackstart capabilities [49].

Financial transmission rights

Being subject to physical laws means that electrical flow in the network often deviates from its intended paths (i.e., contract paths), and financial transmission rights (FTRs) represent a market-based, purely financial solution to the problem of guaranteeing physical transmission rights.

Most simply, FTRs represent “the value of congestion as established by the difference between locational prices of the two nodes that comprise the contract path” [15]. A purchaser who buys FTRs for, say, 100 MWh to be delivered from location A to location B will collect 100 MWh times the price difference between the locational marginal prices (LMPs) at locations A and B. To phrase it differently: the transaction connects the source to the destination at the cost of acquiring the FTR [50]. In effect, FTRs represent a hedge: if the locational marginal prices (LMPs) of two nodes are identical, then there is no difference in value, and the holder of the FTR would not collect anything.

The money to pay for FTR exercise comes from one of two sources, depending on the particular market. If the FTR is an option (i.e., it’s only exercised when there’s congestion), then the money comes from congestion revenues, which are collected by the ISO/RTO. If the FTR is an obligation, then occasionally holders of FTRs must pay if the difference in LMP prices otherwise would have worked out to their favor.

FTRs are typically purchased at auction from transmission owners (who hold auction revenue rights, or ARRs, that are granted by the ISO) for some number of months or years. It is important that the aggregate volume of FTRs be limited to what the grid actually able to transmit; similarly, the auction design must also include an estimate of applicable grid conditions over the timeframe of purchase. Changes in the transmission system will have knock-on effects for congestion, which could drastically affect FTR value. (Isser notes that, clever though they are, FTRs in the real world are far from perfect; auction clearing prices for FTRs typically differ dramatically from the congestion revenues that determine FTR payoffs [15].

For more information on FTRs, the reader is pointed to Hogan’s summary [50] and Kirschen’s *Fundamentals of Power System Economics*, section 5.3.5 [36].

Overall trends and conclusions

Overall, the story of the grid is one of progressive deregulation and increasing competition -- but only at the right price. National policy, implemented mostly by FERC, has been to promote vigorous wholesale competition under the oversight of ISOs/RTOs, and to encourage the use of diverse technical resources -- demand response, renewables, and storage -- to keep wholesale markets as competitive as possible. And while the net effect has been to encourage wind and solar, there is no long-term coordinated federal policy to actively promote renewables as such, (although programs like the American Recovery and Reinvestment Act, which promoted distributed energy, smart grids, and energy storage have also contributed to their increased adoption). Instead, states are taking it upon themselves to advance renewable energy causes through the use of Renewable Portfolio Standards (RPSs). And while successful, it has largely been because renewable energy itself has been seeing continuing price drops compared to older technologies. Future clean energy in the grid is going to be driven largely by cost considerations, and must be accounted for as a part of any project.

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